MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

To the Stockholders of Chevron Corporation

Management of Chevron is responsible for preparing the accompanying Consolidated Financial Statements and the related information appearing in this report. The statements were prepared in accordance with accounting principles generally accepted in the United States of America and fairly represent the transactions and financial position of the company. The financial statements include amounts that are based on management's best estimates and judgment.

As stated in its report included herein, the independent registered public accounting firm of PricewaterhouseCoopers LLP has audited the company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Board of Directors of Chevron has an Audit Committee composed of directors who are not officers or employees of the company. The Audit Committee meets regularly with members of management, the internal auditors and the independent registered public accounting firm to review accounting, internal control, auditing and financial reporting matters. Both the internal auditors and the independent registered public accounting firm have free and direct access to the Audit Committee without the presence of management.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). The company's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the company's management concluded that its internal control over financial reporting was effective as of December 31, 2006.

The company management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

DAVID J. O'REILLY	STEPHEN J. CROWE	MARK A. HUMPHREY
Chairman of the Board and Chief Executive Officer	Vice President and Chief Financial Officer	Vice President and Comptroller

February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Chevron Corporation:

We have completed integrated audits of Chevron Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

CONSOLIDATED FINANCIAL STATEMENTS

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2006, and December 31, 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 14 to the Consolidated Financial Statements, the Company changed its method of accounting for buy/sell contracts on April 1, 2006.

As Discussed in Note 21 to the Consolidated Financial Statements, the Company changed its method of accounting for defined benefit pension and other postretirement plans on December 31, 2006.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

San Francisco, California
February 28, 2007

CONSOLIDATED STATEMENT OF INCOME

Millions of dollars, except per-share amounts

	Year ended December 31 2006	2005	2004
REVENUES AND OTHER INCOME			
Sales and other operating revenues[1,2]	$ 204,892	$ 193,641	$ 150,865
Income from equity affiliates	4,255	3,731	2,582
Other income	971	828	1,853
TOTAL REVENUES AND OTHER INCOME	210,118	198,200	155,300
COSTS AND OTHER DEDUCTIONS			
Purchased crude oil and products[2]	128,151	127,968	94,419
Operating expenses	14,624	12,191	9,832
Selling, general and administrative expenses	5,093	4,828	4,557
Exploration expenses	1,364	743	697
Depreciation, depletion and amortization	7,506	5,913	4,935
Taxes other than on income[1]	20,883	20,782	19,818
Interest and debt expense	451	482	406
Minority interests	70	96	85
TOTAL COSTS AND OTHER DEDUCTIONS	178,142	173,003	134,749
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE	31,976	25,197	20,551
INCOME TAX EXPENSE	14,838	11,098	7,517
INCOME FROM CONTINUING OPERATIONS	17,138	14,099	13,034
INCOME FROM DISCONTINUED OPERATIONS	–	–	294
NET INCOME	$ 17,138	$ 14,099	$ 13,328
PER SHARE OF COMMON STOCK[3]			
INCOME FROM CONTINUING OPERATIONS			
– BASIC	$ 7.84	$ 6.58	$ 6.16
– DILUTED	$ 7.80	$ 6.54	$ 6.14
INCOME FROM DISCONTINUED OPERATIONS			
– BASIC	$ –	$ –	$ 0.14
– DILUTED	$ –	$ –	$ 0.14
NET INCOME			
– BASIC	$ 7.84	$ 6.58	$ 6.30
– DILUTED	$ 7.80	$ 6.54	$ 6.28
[1]Includes excise, value-added and other similar taxes:	$ 9,551	$ 8,719	$ 7,968
[2]Includes amounts in revenues for buy/sell contracts; associated costs are in "Purchased crude oil and products." Refer also to Note 14, on page 67.	$ 6,725	$ 23,822	$ 18,650

[3]All periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Millions of dollars

	Year ended December 31 2006	2005	2004
NET INCOME	$ 17,138	$ 14,099	$ 13,328
Currency translation adjustment			
Unrealized net change arising during period	55	(5)	36
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	(88)	(32)	35
Reclassification to net income of net realized (gain)	–	–	(44)
Total	(88)	(32)	(9)
Net derivatives gain (loss) on hedge transactions			
Net gain (loss) arising during period			
Before income taxes	2	(242)	(8)
Income taxes	6	89	(1)
Reclassification to net income of net realized gain (loss)			
Before income taxes	95	34	–
Income taxes	(36)	(12)	–
Total	67	(131)	(9)
Minimum pension liability adjustment			
Before income taxes	(88)	89	719
Income taxes	50	(31)	(247)
Total	(38)	58	472
OTHER COMPREHENSIVE (LOSS) GAIN, NET OF TAX	(4)	(110)	490
COMPREHENSIVE INCOME	$ 17,134	$ 13,989	$ 13,818

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

Millions of dollars, except per-share amounts

	At December 31	
	2006	2005
ASSETS		
Cash and cash equivalents	$ 10,493	$ 10,043
Marketable securities	953	1,101
Accounts and notes receivable (less allowance: 2006 – $175; 2005 – $156)	17,628	17,184
Inventories:		
Crude oil and petroleum products	3,586	3,182
Chemicals	258	245
Materials, supplies and other	812	694
Total inventories	4,656	4,121
Prepaid expenses and other current assets	2,574	1,887
TOTAL CURRENT ASSETS	36,304	34,336
Long-term receivables, net	2,203	1,686
Investments and advances	18,552	17,057
Properties, plant and equipment, at cost	137,747	127,446
Less: Accumulated depreciation, depletion and amortization	68,889	63,756
Properties, plant and equipment, net	68,858	63,690
Deferred charges and other assets	2,088	4,428
Goodwill	4,623	4,636
TOTAL ASSETS	$ 132,628	$ 125,833
LIABILITIES AND STOCKHOLDERS' EQUITY		
Short-term debt	$ 2,159	$ 739
Accounts payable	16,675	16,074
Accrued liabilities	4,546	3,690
Federal and other taxes on income	3,626	3,127
Other taxes payable	1,403	1,381
TOTAL CURRENT LIABILITIES	28,409	25,011
Long-term debt	7,405	11,807
Capital lease obligations	274	324
Deferred credits and other noncurrent obligations	11,000	10,507
Noncurrent deferred income taxes	11,647	11,262
Reserves for employee benefit plans	4,749	4,046
Minority interests	209	200
TOTAL LIABILITIES	63,693	63,157
Preferred stock (authorized 100,000,000 shares, $1.00 par value; none issued)	–	–
Common stock (authorized 4,000,000,000 shares, $0.75 par value; 2,442,676,580 shares issued at December 31, 2006 and 2005)	1,832	1,832
Capital in excess of par value	14,126	13,894
Retained earnings	68,464	55,738
Notes receivable – key employees	(2)	(3)
Accumulated other comprehensive loss	(2,636)	(429)
Deferred compensation and benefit plan trust	(454)	(486)
Treasury stock, at cost (2006 – 278,118,341 shares; 2005 – 209,989,910 shares)	(12,395)	(7,870)
TOTAL STOCKHOLDERS' EQUITY	68,935	62,676
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 132,628	$ 125,833

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

Millions of dollars

	Year ended December 31		
	2006	2005	2004
OPERATING ACTIVITIES			
Net income	$ 17,138	$ 14,099	$ 13,328
Adjustments			
Depreciation, depletion and amortization	7,506	5,913	4,935
Dry hole expense	520	226	286
Distributions less than income from equity affiliates	(979)	(1,304)	(1,422)
Net before-tax gains on asset retirements and sales	(229)	(134)	(1,882)
Net foreign currency effects	259	62	60
Deferred income tax provision	614	1,393	(224)
Net decrease (increase) in operating working capital	1,044	(54)	430
Minority interest in net income	70	96	85
Increase in long-term receivables	(900)	(191)	(60)
Decrease (increase) in other deferred charges	232	668	(69)
Cash contributions to employee pension plans	(449)	(1,022)	(1,643)
Other	(503)	353	866
NET CASH PROVIDED BY OPERATING ACTIVITIES	24,323	20,105	14,690
INVESTING ACTIVITIES			
Cash portion of Unocal acquisition, net of Unocal cash received	–	(5,934)	–
Capital expenditures	(13,813)	(8,701)	(6,310)
Repayment of loans by equity affiliates	463	57	1,790
Proceeds from asset sales	989	2,681	3,671
Net sales (purchases) of marketable securities	142	336	(450)
Advances to equity affiliate	–	–	(2,200)
NET CASH USED FOR INVESTING ACTIVITIES	(12,219)	(11,561)	(3,499)
FINANCING ACTIVITIES			
Net (payments) borrowings of short-term obligations	(677)	(109)	114
Repayments of long-term debt and other financing obligations	(2,224)	(966)	(1,398)
Cash dividends – common stock	(4,396)	(3,778)	(3,236)
Dividends paid to minority interests	(60)	(98)	(41)
Net purchases of treasury shares	(4,491)	(2,597)	(1,645)
Redemption of preferred stock of subsidiaries	–	(140)	(18)
Proceeds from issuances of long-term debt	–	20	–
NET CASH USED FOR FINANCING ACTIVITIES	(11,848)	(7,668)	(6,224)
EFFECT OF EXCHANGE RATE CHANGES ON CASH AND CASH EQUIVALENTS	194	(124)	58
NET CHANGE IN CASH AND CASH EQUIVALENTS	450	752	5,025
CASH AND CASH EQUIVALENTS AT JANUARY 1	10,043	9,291	4,266
CASH AND CASH EQUIVALENTS AT DECEMBER 31	$ 10,493	$ 10,043	$ 9,291

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

Shares in thousands; amounts in millions of dollars

	2006		2005		2004	
	Shares	Amount	Shares	Amount	Shares	Amount
PREFERRED STOCK	–	$ –	–	$ –	–	$ –
COMMON STOCK						
Balance at January 1	2,442,677	$ 1,832	2,274,032	$ 1,706	2,274,042	$ 1,706
Shares issued for Unocal acquisition	–	–	168,645	126	–	–
Conversion of Texaco Inc. acquisition	–	–	–	–	(10)	–
BALANCE AT DECEMBER 31	2,442,677	$ 1,832	2,442,677	$ 1,832	2,274,032	$ 1,706
CAPITAL IN EXCESS OF PAR						
Balance at January 1		$ 13,894		$ 4,160		$ 4,002
Shares issued for Unocal acquisition		–		9,585		–
Treasury stock transactions		232		149		158
BALANCE AT DECEMBER 31		$ 14,126		$ 13,894		$ 4,160
RETAINED EARNINGS						
Balance at January 1		$ 55,738		$ 45,414		$ 35,315
Net income		17,138		14,099		13,328
Cash dividends on common stock		(4,396)		(3,778)		(3,236)
Adoption of EITF 04-6, "Accounting for Stripping Costs Incurred during Production in the Mining Industry"		(19)				–
Tax benefit from dividends paid on unallocated ESOP shares and other		3		3		7
BALANCE AT DECEMBER 31		$ 68,464		$ 55,738		$ 45,414
NOTES RECEIVABLE – KEY EMPLOYEES		$ (2)		$ (3)		$ –
ACCUMULATED OTHER COMPREHENSIVE LOSS						
Currency translation adjustment						
Balance at January 1		$ (145)		$ (140)		$ (176)
Change during year		55		(5)		36
Balance at December 31		$ (90)		$ (145)		$ (140)
Pension and other postretirement benefit plans						
Balance at January 1		$ (344)		$ (402)		$ (874)
Change to minimum pension liability during year		(38)		58		472
Adoption of FAS 158, "Employers' Accounting for Defined Pension and Other Postretirement Plans"		(2,203)		–		
Balance at December 31		$ (2,585)		$ (344)		$ (402)
Unrealized net holding gain on securities						
Balance at January 1		$ 88		$ 120		$ 129
Change during year		(88)		(32)		(9)
Balance at December 31		$ –		$ 88		$ 120
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		$ (28)		$ 103		$ 112
Change during year		67		(131)		(9)
Balance at December 31		$ 39		$ (28)		$ 103
BALANCE AT DECEMBER 31		$ (2,636)		$ (429)		$ (319)
DEFERRED COMPENSATION AND BENEFIT PLAN TRUST						
DEFERRED COMPENSATION						
Balance at January 1		$ (246)		$ (367)		$ (362)
Net reduction of ESOP debt and other		32		121		(5)
BALANCE AT DECEMBER 31		(214)		(246)		(367)
BENEFIT PLAN TRUST (COMMON STOCK)	14,168	(240)	14,168	(240)	14,168	(240)
BALANCE AT DECEMBER 31	14,168	$ (454)	14,168	$ (486)	14,168	$ (607)
TREASURY STOCK AT COST						
Balance at January 1	209,990	$ (7,870)	166,912	$ (5,124)	135,747	$ (3,317)
Purchases	80,369	(5,033)	52,013	(3,029)	42,607	(2,122)
Issuances – mainly employee benefit plans	(12,241)	508	(8,935)	283	(11,442)	315
BALANCE AT DECEMBER 31	278,118	$ (12,395)	209,990	$ (7,870)	166,912	$ (5,124)
TOTAL STOCKHOLDERS' EQUITY AT DECEMBER 31		$ 68,935		$ 62,676		$ 45,230

See accompanying Notes to the Consolidated Financial Statements.

NOTE 1.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General Exploration and production (upstream) operations consist of exploring for, developing and producing crude oil and natural gas and also marketing natural gas. Refining, marketing and transportation (downstream) operations relate to refining crude oil into finished petroleum products; marketing crude oil and the many products derived from petroleum; and transporting crude oil, natural gas and petroleum products by pipeline, marine vessel, motor equipment and rail car. Chemical operations include the manufacture and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant oil additives.

The company's Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in the United States of America. These require the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. Although the company uses its best estimates and judgments, actual results could differ from these estimates as future confirming events occur.

The nature of the company's operations and the many countries in which it operates subject the company to changing economic, regulatory and political conditions. The company does not believe it is vulnerable to the risk of near-term severe impact as a result of any concentration of its activities.

Subsidiary and Affiliated Companies The Consolidated Financial Statements include the accounts of controlled subsidiary companies more than 50 percent-owned and variable-interest entities in which the company is the primary beneficiary. Undivided interests in oil and gas joint ventures and certain other assets are consolidated on a proportionate basis. Investments in and advances to affiliates in which the company has a substantial ownership interest of approximately 20 percent to 50 percent or for which the company exercises significant influence but not control over policy decisions are accounted for by the equity method. As part of that accounting, the company recognizes gains and losses that arise from the issuance of stock by an affiliate that results in changes in the company's proportionate share of the dollar amount of the affiliate's equity currently in income. Deferred income taxes are provided for these gains and losses.

Investments are assessed for possible impairment when events indicate that the fair value of the investment may be below the company's carrying value. When such a condition is deemed to be other than temporary, the carrying value of the investment is written down to its fair value, and the amount of the write-down is included in net income. In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee's financial performance, and the company's ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment's market value. The new cost basis of investments in these equity investees is not changed for subsequent recoveries in fair value. Subsequent recoveries in the carrying value of other investments are reported in "Other comprehensive income."

Differences between the company's carrying value of an equity investment and its underlying equity in the net assets of the affiliate are assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the various factors giving rise to the difference. The company's share of the affiliate's reported earnings is adjusted quarterly when appropriate to reflect the difference between these allocated values and the affiliate's historical book values.

Derivatives The majority of the company's activity in commodity derivative instruments is intended to manage the financial risk posed by physical transactions. For some of this derivative activity, generally limited to large, discrete or infrequently occurring transactions, the company may elect to apply fair value or cash flow hedge accounting. For other similar derivative instruments, generally because of the short-term nature of the contracts or their limited use, the company does not apply hedge accounting, and changes in the fair value of those contracts are reflected in current income. For the company's trading activity, gains and losses from the derivative instruments are reported in current income. For derivative instruments relating to foreign currency exposures, gains and losses are reported in current income. Interest rate swaps – hedging a portion of the company's fixed-rate debt – are accounted for as fair value hedges, whereas interest rate swaps relating to a portion of the company's floating-rate debt are recorded at fair value on the Consolidated Balance Sheet, with resulting gains and losses reflected in income.

Short-Term Investments All short-term investments are classified as available for sale and are in highly liquid debt securities. Those investments that are part of the company's cash management portfolio and have original maturities of three months or less are reported as "Cash equivalents." The balance of the short-term investments is reported as "Marketable securities" and are marked-to-market, with any unrealized gains or losses included in "Other comprehensive income."

Inventories Crude oil, petroleum products and chemicals are generally stated at cost, using a Last-In, First-Out (LIFO) method. In the aggregate, these costs are below market. "Materials, supplies and other" inventories generally are stated at average cost.

Properties, Plant and Equipment The successful efforts method is used for crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs are also capitalized for exploratory wells that have found crude oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. All other exploratory wells and costs are expensed. Refer to Note 20, beginning on page 71, for additional discussion of accounting for suspended exploratory well costs.

Long-lived assets to be held and used, including proved crude oil and natural gas properties, are assessed for possible impairment by comparing their carrying values with their associated undiscounted future net before-tax cash flows. Events that can trigger assessments for possible impairments include write-downs of proved reserves based on field performance, significant decreases in the market value of an asset, significant change in the extent or manner of use of or a physical change in an asset, and a more-likely-than-not expectation that a long-lived asset or asset group will be sold or otherwise disposed of significantly sooner than the end of its previously estimated useful life. Impaired assets are written down to their estimated fair values, generally their discounted future net before-tax cash flows. For proved crude oil and natural gas properties in the United States, the company generally performs the impairment review on an individual field basis. Outside the United States, reviews are performed on a country, concession, development area, or field basis, as appropriate. In the refining, marketing, transportation and chemical areas, impairment reviews are generally done on the basis of a refinery, a plant, a marketing area or marketing assets by country. Impairment amounts are recorded as incremental "Depreciation, depletion and amortization" expense.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value.

As required under Financial Accounting Standards Board (FASB) Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143), the fair value of a liability for an ARO is recorded as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 24, on page 82, relating to AROs.

Depreciation and depletion of all capitalized costs of proved crude oil and natural gas producing properties, except mineral interests, are expensed using the unit-of-production method by individual field as the proved developed reserves are produced. Depletion expenses for capitalized costs of proved mineral interests are recognized using the unit-of-production method by individual field as the related proved reserves are produced. Periodic valuation provisions for impairment of capitalized costs of unproved mineral interests are expensed.

Depreciation and depletion expenses for mining assets are determined using the unit-of-production method as the proven reserves are produced. The capitalized costs of all other plant and equipment are depreciated or amortized over their estimated useful lives. In general, the declining-balance method is used to depreciate plant and equipment in the United States; the straight-line method generally is used to depreciate international plant and equipment and to amortize all capitalized leased assets.

Gains or losses are not recognized for normal retirements of properties, plant and equipment subject to composite group amortization or depreciation. Gains or losses from abnormal retirements are recorded as expenses and from sales as "Other income."

Expenditures for maintenance (including those for planned major maintenance projects), repairs and minor renewals to maintain facilities in operating condition are generally expensed as incurred. Major replacements and renewals are capitalized.

Goodwill Goodwill acquired in a business combination is not subject to amortization. As required by FASB Statement No. 142, *Goodwill and Other Intangible Assets*, the company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The goodwill arising from the Unocal acquisition is described in more detail in Note 2, beginning on page 58.

Environmental Expenditures Environmental expenditures that relate to ongoing operations or to conditions caused by past operations are expensed. Expenditures that create future benefits or contribute to future revenue generation are capitalized.

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For the company's U.S. and Canadian marketing facilities, the accrual is based in part on the probability that a future remediation commitment will be required. For crude oil, natural gas and mineral producing properties, a liability for an asset retirement obligation is made, following FAS 143. Refer to Note 24, on page 82, for a discussion of FAS 143.

For federal Superfund sites and analogous sites under state laws, the company records a liability for its designated share of the probable and estimable costs and probable amounts for other potentially responsible parties when mandated by the regulatory agencies because the other parties are not able to pay their respective shares.

The gross amount of environmental liabilities is based on the company's best estimate of future costs using currently available technology and applying current regulations and the company's own internal environmental policies. Future amounts are not discounted. Recoveries or reimbursements are recorded as assets when receipt is reasonably assured.

Currency Translation The U.S. dollar is the functional currency for substantially all of the company's consolidated operations and those of its equity affiliates. For those operations, all gains and losses from currency translations are currently included in income. The cumulative translation effects for those few entities, both consolidated and affiliated, using functional currencies other than the U.S. dollar are included in the currency translation adjustment in "Stockholders' Equity."

Revenue Recognition Revenues associated with sales of crude oil, natural gas, coal, petroleum and chemicals products, and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which Chevron has an interest with other producers are generally recognized on the basis of the company's net working interest (entitlement method). Excise, value-added and other similar taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer are presented on a gross basis. The associated amounts are shown as a footnote to the Consolidated Statement of Income on page 51. Refer to Note 14, on page 67, for a discussion of the accounting for buy/sell arrangements.

Stock Options and Other Share-Based Compensation Effective July 1, 2005, the company adopted the provisions of FASB Statement No. 123R, *Share-Based Payment* (FAS 123R), for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25), and related interpretations and disclosure requirements established by FASB Statement No. 123, *Accounting for Stock-Based Compensation* (FAS 123).

Refer to Note 22, beginning on page 77, for a description of the company's share-based compensation plans, information related to awards granted under those plans and additional information on the company's adoption of FAS 123R.

The following table illustrates the effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123 to stock options, stock appreciation rights, performance units and restricted stock units for periods prior to adoption of FAS 123R and the actual effect on 2005 net income and earnings per share for periods after adoption of FAS 123R.

	Year ended December 31	
	2005	2004
Net income, as reported	$ 14,099	$ 13,328
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	81	42
Deduct: Total stock-based employee compensation expense determined under fair-valued-based method for awards, net of related tax effects[1]	(108)	(84)
Pro forma net income	$ 14,072	$ 13,286
Net income per share:[2]		
Basic – as reported	$ 6.58	$ 6.30
Basic – pro forma	$ 6.56	$ 6.28
Diluted – as reported	$ 6.54	$ 6.28
Diluted – pro forma	$ 6.53	$ 6.26

[1] Fair value determined using the Black-Scholes option-pricing model.
[2] Per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

NOTE 2.

ACQUISITION OF UNOCAL CORPORATION

In August 2005, the company acquired Unocal Corporation (Unocal), an independent oil and gas exploration and production company. Unocal's principal upstream operations were in North America and Asia, including the Caspian region. Also located in Asia were Unocal's geothermal energy and electrical power businesses. Other activities included ownership interests in proprietary and common carrier pipelines, natural gas storage facilities and mining operations.

The aggregate purchase price of Unocal was approximately $17,288. A third-party appraisal firm was engaged to assist the company in the process of determining the fair values of Unocal's tangible and intangible assets. The final purchase-price allocation to the assets and liabilities acquired was completed as of June 30, 2006.

The acquisition was accounted for under the rules of FASB Statement No. 141, *Business Combinations*. The following table summarizes the final purchase-price allocation:

Current assets	$ 3,573
Investments and long-term receivables	1,695
Properties	17,285
Goodwill	4,820
Other assets	2,174
Total assets acquired	29,547
Current liabilities	(2,364)
Long-term debt and capital leases	(2,392)
Deferred income taxes	(4,009)
Other liabilities	(3,494)
Total liabilities assumed	(12,259)
Net assets acquired	$ 17,288

The $4,820 of goodwill, which represents benefits of the acquisition that are additional to the fair values of the other net assets acquired, was assigned to the upstream segment. The goodwill is not deductible for tax purposes. The goodwill balance was reviewed for possible impairment as of June 30, 2006, according to the requirements of FASB Statement No. 142, *Goodwill and Other Intangible Assets*, to test goodwill for impairment on an annual basis. Goodwill was determined not to be impaired at that time, and no events have occurred subsequently that would necessitate an additional impairment review.

The following unaudited pro forma summary presents the results of operations as if the acquisition of Unocal had occurred at the beginning of each period:

	Year ended December 31	
	2005	2004
Sales and other operating revenues	$ 198,762	$ 158,471
Net income	14,967	14,164
Net income per share of common stock		
Basic	$ 6.68	$ 6.22
Diluted	$ 6.64	$ 6.19

The pro forma summary uses estimates and assumptions based on information available at the time. Management believes the estimates and assumptions to be reasonable; however, actual results may differ significantly from this pro forma financial information. The pro forma information does not reflect any synergistic savings that might be achieved from combining the operations and is not intended to reflect the actual results that would have occurred had the companies actually been combined during the periods presented.

NOTE 3.

INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS

	Year ended December 31		
	2006	2005	2004
Net decrease (increase) in operating working capital was composed of the following:			
Decrease (increase) in accounts and notes receivable	$ 17	$ (3,164)	$ (2,515)
Increase in inventories	(536)	(968)	(298)
Increase in prepaid expenses and other current assets	(31)	(54)	(76)
Increase in accounts payable and accrued liabilities	1,246	3,851	2,175
Increase in income and other taxes payable	348	281	1,144
Net decrease (increase) in operating working capital	$ 1,044	$ (54)	$ 430
Net cash provided by operating activities includes the following cash payments for interest and income taxes:			
Interest paid on debt (net of capitalized interest)	$ 470	$ 455	$ 422
Income taxes	$ 13,806	$ 8,875	$ 6,679
Net (purchases) sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	$ (1,271)	$ (918)	$ (1,951)
Marketable securities sold	1,413	1,254	1,501
Net sales (purchases) of marketable securities	$ 142	$ 336	$ (450)

The Consolidated Statement of Cash Flows excludes the effects of noncash transactions. In October 2006, operating service agreements in Venezuela were converted to joint stock companies. Upon conversion, the company reclassified $441 of long-term receivables, $132 of accounts receivable and $45 of properties, plant and equipment to investments in equity affiliates. Refer also to Note 21 on page 72 for the noncash effects associated with the implementation of FASB Statement No. 158, *Employers' Accounting for Defined Pension and Other Postretirement Plans*.

In accordance with the cash-flow classification requirements of FAS 123R, *Share-Based Payment*, the "Net decrease (increase) in operating working capital" includes reductions of $94 and $20 for excess income tax benefits associated with stock options exercised during 2006 and 2005, respectively. These amounts are offset by "Net purchases of treasury shares."

The "Net purchases of treasury shares" represents the cost of common shares acquired in the open market less the cost of shares issued for share-based compensation plans. Open-market purchases totaled $5,033, $3,029 and $2,122 in 2006, 2005 and 2004, respectively.

NOTE 3. INFORMATION RELATING TO THE CONSOLIDATED STATEMENT OF CASH FLOWS – Continued

In May 2006, the company's investment in Dynegy Series C preferred stock was redeemed at its face value of $400. Upon redemption of the preferred stock, the company recorded a before-tax gain of $130 ($87 after tax). The $130 gain is included in the Consolidated Statement of Income as "Income from equity affiliates."

The 2005 "cash portion of Unocal acquisition, net of Unocal cash received" represents the purchase price, net of $1,600 of cash received. The aggregate purchase price of Unocal was approximately $17,288. Refer to Note 2, starting on page 58, for additional discussion of the Unocal acquisition.

The major components of "Capital expenditures" and the reconciliation of this amount to the reported capital and exploratory expenditures, including equity affiliates, presented in Management's Discussion and Analysis, beginning on page 26, are presented in the following table:

	Year ended December 31		
	2006	2005	2004
Additions to properties, plant and equipment*	$12,800	$ 8,154	$ 5,798
Additions to investments	880	459	303
Current-year dry hole expenditures	400	198	228
Payments for other liabilities and assets, net	(267)	(110)	(19)
Capital expenditures	13,813	8,701	6,310
Expensed exploration expenditures	844	517	412
Assets acquired through capital lease obligations and other financing obligations	35	164	31
Capital and exploratory expenditures, excluding equity affiliates	14,692	9,382	6,753
Equity in affiliates' expenditures	1,919	1,681	1,562
Capital and exploratory expenditures, including equity affiliates	$ 16,611	$ 11,063	$ 8,315

*Net of noncash additions of $440 in 2006, $435 in 2005 and $212 in 2004.

NOTE 4.

SUMMARIZED FINANCIAL DATA – CHEVRON U.S.A. INC.

Chevron U.S.A. Inc. (CUSA) is a major subsidiary of Chevron Corporation. CUSA and its subsidiaries manage and operate most of Chevron's U.S. businesses. Assets include those related to the exploration and production of crude oil, natural gas and natural gas liquids and those associated with the refining, marketing, supply and distribution of products derived from petroleum, other than natural gas liquids, excluding most of the regulated pipeline operations of Chevron. CUSA also holds Chevron's investments in the Chevron Phillips Chemical Company LLC (CPChem) joint venture and Dynegy Inc. (Dynegy), which are accounted for using the equity method.

	Year ended December 31		
	2006	2005	2004
Sales and other operating revenues	$ 146,447	$ 138,296	$ 108,351
Total costs and other deductions	138,494	132,180	102,180
Net income	5,399	4,693	4,773

	At December 31	
	2006	2005
Current assets	$ 26,356	$ 27,878
Other assets	23,200	20,611
Current liabilities	17,250	20,286
Other liabilities	11,501	12,897
Net equity	20,805	15,306
Memo: Total debt	$ 6,020	$ 8,353

NOTE 5.

SUMMARIZED FINANCIAL DATA – CHEVRON TRANSPORT CORPORATION LTD.

Chevron Transport Corporation Ltd. (CTC), incorporated in Bermuda, is an indirect, wholly owned subsidiary of Chevron Corporation. CTC is the principal operator of Chevron's international tanker fleet and is engaged in the marine transportation of crude oil and refined petroleum products. Most of CTC's shipping revenue is derived from providing transportation services to other Chevron companies. Chevron Corporation has fully and unconditionally guaranteed this subsidiary's obligations in connection with certain debt securities issued by a third party. Summarized financial information for CTC and its consolidated subsidiaries is presented in the following table:

	Year ended December 31		
	2006	2005	2004
Sales and other operating revenues	$ 692	$ 640	$ 660
Total costs and other deductions	602	509	495
Net income	119	113	160

	At December 31	
	2006	2005
Current assets	$ 413	$ 358
Other assets	345	283
Current liabilities	92	119
Other liabilities	250	243
Net equity	416	279

There were no restrictions on CTC's ability to pay dividends or make loans or advances at December 31, 2006.

NOTE 6.

STOCKHOLDERS' EQUITY

Retained earnings at December 31, 2006 and 2005, included approximately $5,580 and $5,000, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2006, about 134 million shares of Chevron's common stock remained available for issuance from the 160 million shares that were reserved for issuance under the Chevron Corporation Long-Term Incentive Plan (LTIP), as amended and restated, which was approved by the stockholders in 2004. In addition, approximately 503,000 shares remain available for issuance from the 800,000 shares of the company's common stock that were reserved for awards under the Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan (Non-Employee Directors' Plan), which was approved by stockholders in 2003. Refer to Note 25, on page 82, for a discussion of the company's common stock split in 2004.

NOTE 7.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments Chevron is exposed to market risks related to price volatility of crude oil, refined products, natural gas, natural gas liquids, liquefied natural gas and refinery feedstocks.

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including: firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids, and feedstock for company refineries. The company also uses derivative commodity instruments for limited trading purposes.

The company uses International Swaps Dealers Association agreements to govern derivative contracts with certain counterparties to mitigate credit risk. Depending on the nature of the derivative transactions, bilateral collateral arrangements may also be required. When the company is engaged in more than one outstanding derivative transaction with the same counterparty and also has a legally enforceable netting agreement with that counterparty, the net marked-to-market exposure represents the netting of the positive and negative exposures with that counterparty and is a reasonable measure of the company's credit risk exposure. The company also uses other netting agreements with certain counterparties with which it conducts significant transactions to mitigate credit risk.

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as "Accounts and notes receivable," "Accounts payable," "Long-term receivables – net" and "Deferred credits and other noncurrent obligations." Gains and losses on the company's risk management activities are reported as either "Sales and other operating revenues" or "Purchased crude oil and products," whereas trading gains and losses are reported as "Other income."

Foreign Currency The company enters into forward exchange contracts, generally with terms of 180 days or less, to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments, forecasted to occur within 180 days. The forward exchange contracts are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

The fair values of the outstanding contracts are reported on the Consolidated Balance Sheet as "Accounts and notes receivable" or "Accounts payable," with gains and losses reported as "Other income."

Interest Rates The company enters into interest rate swaps as part of its overall strategy to manage the interest rate risk on its debt. Under the terms of the swaps, net cash settlements are based on the difference between fixed-rate and floating-rate interest amounts calculated by reference to agreed notional principal amounts. Interest rate swaps related to a portion of the company's fixed-rate debt are accounted for as fair value hedges, whereas interest rate swaps related to a portion of the company's floating-rate debt are recorded at fair value on the balance sheet with resulting gains and losses reflected in income.

Fair values of the interest rate swaps are reported on the Consolidated Balance Sheet as "Accounts and notes receivable" or "Accounts payable," with gains and losses reported directly in income as part of "Interest and debt expense."

Fair Value Fair values are derived either from quoted market prices or, if not available, the present value of the expected cash flows. The fair values reflect the cash that would have been received or paid if the instruments were settled at year-end.

Long-term debt of $5,131 and $7,424 had estimated fair values of $5,621 and $7,945 at December 31, 2006 and 2005, respectively.

The company holds cash equivalents and marketable securities in U.S. and non-U.S. portfolios. Eurodollar bonds, floating-rate notes, time deposits and commercial paper are the primary instruments held. Cash equivalents and marketable securities had fair values of $9,200 and $8,995 at December 31, 2006 and 2005, respectively. Of these balances, $8,247 and $7,894 at the respective year-ends were classified as cash equivalents that had average maturities under 90 days. The remainder, classified as marketable securities, had average maturities of approximately 1.4 years.

For the financial and derivative instruments discussed above, there was not a material change in market risk from that presented in 2005.

Fair values of other financial and derivative instruments at the end of 2006 and 2005 were not material.

Concentrations of Credit Risk The company's financial instruments that are exposed to concentrations of credit risk consist primarily of its cash equivalents, marketable securities, derivative financial instruments and trade receivables. The company's short-term investments are placed with a wide array of finan-

NOTE 7. FINANCIAL AND DERIVATIVE INSTRUMENTS – Continued

cial institutions with high credit ratings. This diversified investment policy limits the company's exposure both to credit risk and to concentrations of credit risk. Similar standards of diversity and creditworthiness are applied to the company's counterparties in derivative instruments.

The trade receivable balances, reflecting the company's diversified sources of revenue, are dispersed among the company's broad customer base worldwide. As a consequence, the company believes concentrations of credit risk are limited. The company routinely assesses the financial strength of its customers. When the financial strength of a customer is not considered sufficient, requiring Letters of Credit is a principal method used to support sales to customers.

NOTE 8.

OPERATING SEGMENTS AND GEOGRAPHIC DATA

Although each subsidiary of Chevron is responsible for its own affairs, Chevron Corporation manages its investments in these subsidiaries and their affiliates. For this purpose, the investments are grouped as follows: upstream – exploration and production; downstream – refining, marketing and transportation; chemicals; and all other. The first three of these groupings represent the company's "reportable segments" and "operating segments" as defined in Financial Accounting Standards Board (FASB) Statement No. 131, *Disclosures About Segments of an Enterprise and Related Information* (FAS 131).

The segments are separately managed for investment purposes under a structure that includes "segment managers" who report to the company's "chief operating decision maker" (CODM) (terms as defined in FAS 131). The CODM is the company's Executive Committee, a committee of senior officers that includes the Chief Executive Officer and that, in turn, reports to the Board of Directors of Chevron Corporation.

The operating segments represent components of the company as described in FAS 131 terms that engage in activities (a) from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the CODM, which makes decisions about resources to be allocated to the segments and to assess their performance; and (c) for which discrete financial information is available.

Segment managers for the reportable segments are accountable directly to and maintain regular contact with the company's CODM to discuss the segment's operating activities and financial performance. The CODM approves annual capital and exploratory budgets at the reportable segment level, as well as reviews capital and exploratory funding for major projects and approves major changes to the annual capital and exploratory budgets. However, business-unit managers within the operating segments are directly responsible for decisions relating to project implementation and all other matters connected with daily operations. Company officers who are members of the Executive Committee also have individual management responsibilities and participate in other committees for purposes other than acting as the CODM.

"All Other" activities include the company's interest in Dynegy, mining operations, power generation businesses, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, alternative fuels, and technology companies.

The company's primary country of operation is the United States of America, its country of domicile. Other components of the company's operations are reported as "International" (outside the United States).

Segment Earnings The company evaluates the performance of its operating segments on an after-tax basis, without considering the effects of debt financing interest expense or investment interest income, both of which are managed by the company on a worldwide basis. Corporate administrative costs and assets are not allocated to the operating segments. However, operating segments are billed for the direct use of corporate services. Nonbillable costs remain at the corporate level in "All Other." After-tax segment income from continuing operations is presented in the following table:

	Year ended December 31		
	2006	2005	2004
Income From Continuing Operations			
Upstream			
United States	$ 4,270	$ 4,168	$ 3,868
International	8,872	7,556	5,622
Total Upstream	13,142	11,724	9,490
Downstream			
United States	1,938	980	1,261
International	2,035	1,786	1,989
Total Downstream	3,973	2,766	3,250
Chemicals			
United States	430	240	251
International	109	58	63
Total Chemicals	539	298	314
Total Segment Income	17,654	14,788	13,054
All Other			
Interest expense	(312)	(337)	(257)
Interest income	380	266	129
Other	(584)	(618)	108
Income From Continuing Operations	17,138	14,099	13,034
Income From Discontinued Operations	–	–	294
Net Income	$ 17,138	$ 14,099	$ 13,328

NOTE 8. OPERATING SEGMENTS AND GEOGRAPHIC DATA – Continued

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2006 and 2005 are as follows:

	At December 31	
	2006	2005
Upstream		
United States	$ 20,727	$ 19,006
International	51,844	46,501
Goodwill	4,623	4,636
Total Upstream	77,194	70,143
Downstream		
United States	13,482	12,273
International	22,892	22,294
Total Downstream	36,374	34,567
Chemicals		
United States	2,568	2,452
International	832	727
Total Chemicals	3,400	3,179
Total Segment Assets	116,968	107,889
All Other*		
United States	8,481	9,234
International	7,179	8,710
Total All Other	15,660	17,944
Total Assets – United States	45,258	42,965
Total Assets – International	82,747	78,232
Goodwill	4,623	4,636
Total Assets	$ 132,628	$ 125,833

*"All Other" assets consist primarily of worldwide cash, cash equivalents and marketable securities, real estate, information systems, the company's investment in Dynegy, mining operations, power generation businesses, technology companies, and assets of the corporate administrative functions.

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2006, 2005 and 2004 are presented in the following table. Products are transferred between operating segments at internal product values that approximate market prices.

Revenues for the upstream segment are derived primarily from the production and sale of crude oil and natural gas, as well as the sale of third-party production of natural gas. Revenues for the downstream segment are derived from the refining and marketing of petroleum products, such as gasoline, jet fuel, gas oils, kerosene, lubricants, residual fuel oils and other products derived from crude oil. This segment also generates revenues from the transportation and trading of crude oil and refined products. Revenues for the chemicals segment are derived primarily from the manufacture and sale of additives for lubricants and fuel. "All Other" activities include revenues from mining operations of coal and other minerals, power generation businesses, insurance operations, real estate activities, and technology companies.

Other than the United States, no single country accounted for 10 percent or more of the company's total sales and other operating revenues in 2006.

	Year ended December 31		
	2006	2005	2004
Upstream			
United States	$ 18,061	$ 16,044	$ 8,242
Intersegment	10,069	8,651	8,121
Total United States	28,130	24,695	16,363
International	14,560	10,190	7,246
Intersegment	17,139	13,652	10,184
Total International	31,699	23,842	17,430
Total Upstream	59,829	48,537	33,793
Downstream			
United States	69,367	73,721	57,723
Excise and other similar taxes	4,829	4,521	4,147
Intersegment	533	535	179
Total United States	74,729	78,777	62,049
International	91,325	83,223	67,944
Excise and other similar taxes	4,657	4,184	3,810
Intersegment	37	14	87
Total International	96,019	87,421	71,841
Total Downstream	170,748	166,198	133,890
Chemicals			
United States	372	343	347
Excise and other similar taxes	2	–	–
Intersegment	243	241	188
Total United States	617	584	535
International	959	760	747
Excise and other similar taxes	63	14	11
Intersegment	160	131	107
Total International	1,182	905	865
Total Chemicals	1,799	1,489	1,400
All Other			
United States	653	597	551
Intersegment	584	514	431
Total United States	1,237	1,111	982
International	44	44	97
Intersegment	23	26	16
Total International	67	70	113
Total All Other	1,304	1,181	1,095
Segment Sales and Other Operating Revenues			
United States	104,713	105,167	79,929
International	128,967	112,238	90,249
Total Segment Sales and Other Operating Revenues	233,680	217,405	170,178
Elimination of intersegment sales	(28,788)	(23,764)	(19,313)
Total Sales and Other Operating Revenues*	$ 204,892	$ 193,641	$ 150,865

*Includes buy/sell contracts of $6,725 in 2006, $23,822 in 2005 and $18,650 in 2004. Substantially all of the amounts in each period relates to the downstream segment. Refer to Note 14, on page 67, for a discussion of the company's accounting for buy/sell contracts.

NOTE 8. OPERATING SEGMENTS AND GEOGRAPHIC DATA - Continued

Segment Income Taxes Segment income tax expenses for the years 2006, 2005 and 2004 are as follows:

	Year ended December 31		
	2006	2005	2004
Upstream			
United States	$ 2,668	$ 2,330	$ 2,308
International	10,987	8,440	5,041
Total Upstream	13,655	10,770	7,349
Downstream			
United States	1,162	575	739
International	586	576	442
Total Downstream	1,748	1,151	1,181
Chemicals			
United States	213	99	47
International	30	25	17
Total Chemicals	243	124	64
All Other	(808)	(947)	(1,077)
Income Tax Expense From Continuing Operations*	$ 14,838	$ 11,098	$ 7,517

*Income tax expense of $100 related to discontinued operations for 2004 is not included.

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 12, beginning on page 65. Information related to properties, plant and equipment by segment is contained in Note 13, on page 67.

NOTE 9.

LEASE COMMITMENTS

Certain noncancelable leases are classified as capital leases, and the leased assets are included as part of "Properties, plant and equipment, at cost." Such leasing arrangements involve tanker charters, crude oil production and processing equipment, service stations, and other facilities. Other leases are classified as operating leases and are not capitalized. The payments on such leases are recorded as expense. Details of the capitalized leased assets are as follows:

	At December 31	
	2006	2005
Upstream	$ 461	$ 442
Downstream	896	837
Total	1,357	1,279
Less: Accumulated amortization	813	745
Net capitalized leased assets	$ 544	$ 534

Rental expenses incurred for operating leases during 2006, 2005 and 2004 were as follows:

	Year ended December 31		
	2006	2005	2004
Minimum rentals	$ 2,326	$ 2,102	$ 2,093
Contingent rentals	6	6	7
Total	2,332	2,108	2,100
Less: Sublease rental income	33	43	40
Net rental expense	$ 2,299	$ 2,065	$ 2,060

Contingent rentals are based on factors other than the passage of time, principally sales volumes at leased service stations. Certain leases include escalation clauses for adjusting rentals to reflect changes in price indices, renewal options ranging up to 25 years, and options to purchase the leased property during or at the end of the initial or renewal lease period for the fair market value or other specified amount at that time.

At December 31, 2006, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a noncancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases
Year: 2007	$ 509	$ 91
2008	507	80
2009	477	81
2010	390	59
2011	311	57
Thereafter	864	520
Total	$ 3,058	$ 888
Less: Amounts representing interest and executory costs		(262)
Net present values		626
Less: Capital lease obligations included in short-term debt		(352)
Long-term capital lease obligations		$ 274

NOTE 10.

RESTRUCTURING AND REORGANIZATION COSTS

In connection with the Unocal acquisition, the company implemented a restructuring and reorganization program as part of the effort to capture the synergies of the combined companies by eliminating redundant operations, consolidating offices and facilities, and sharing common services and functions.

As part of the restructuring and reorganization, approximately 600 employees were eligible for severance payments. Most of the associated positions are in the United States and relate primarily to corporate and upstream executive and administrative functions. By year-end 2006, the program was substantially complete.

An accrual of $106 was established as part of the purchase-price allocation for Unocal. The $11 balance at year-end 2006 was classified as a current liability on the Consolidated Balance Sheet. Activity for this accrual is shown in the table below.

Amounts before tax	2006	2005
Balance at January 1	$ 44	$ –
Additions/adjustments	(14)	106
Payments	(19)	(62)
Balance at December 31	$ 11	$ 44

Shown in the table below is the activity for the company's liability related to various other reorganizations and restructurings across several businesses and corporate departments. The $17 balance at year-end 2006 was also classified as a current liability on the Consolidated Balance Sheet. The associated charges or credits during the periods were categorized as "Operating expenses" or "Selling, general and administrative expenses" on the Consolidated Statement of Income.

Activity for the company's liability related to other various reorganizations and restructurings is summarized in the following table:

Amounts before tax	2006	2005
Balance at January 1	$ 47	$ 119
Additions/adjustments	(7)	(10)
Payments	(23)	(62)
Balance at December 31	$ 17	$ 47

NOTE 11.

ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

At December 31, 2004, the company classified $162 of net properties, plant and equipment as "Assets held for sale" on the Consolidated Balance Sheet. Assets in this category related to a group of service stations outside the United States.

Summarized income statement information relating to discontinued operations is as follows:

	Year ended December 31		
	2006	2005	2004
Revenues and other income	$ –	$ –	$ 635
Income from discontinued operations before income tax expense	–	–	394
Income from discontinued operations, net of tax	–	–	294

Not all assets sold or to be disposed of are classified as discontinued operations, mainly because the cash flows from the assets were not, or will not be, eliminated from the ongoing operations of the company.

Subsequent to December 31, 2006, approximately $300 of the company's refining assets in the Netherlands met the criteria for classifying the assets as held for sale. The company expects to record a gain upon close of sale, which is subject to signing of the sales agreement and obtaining necessary regulatory approvals.

NOTE 12.

INVESTMENTS AND ADVANCES

Equity in earnings, together with investments in and advances to companies accounted for using the equity method and other investments accounted for at or below cost, are shown in the table below. For certain equity affiliates, Chevron pays its share of some income taxes directly. For such affiliates, the equity in earnings do not include these taxes, which are reported on the Consolidated Statement of Income as "Income tax expense."

	Investments and Advances At December 31		Equity in Earnings Year ended December 31		
	2006	2005	2006	2005	2004
Upstream					
Tengizchevroil	$ 5,507	$ 5,007	$ 1,817	$1,514	$ 950
Hamaca	928	1,189	319	390	98
Petroboscan	712	–	31	–	–
Other	682	679	123	139	148
Total Upstream	7,829	6,875	2,290	2,043	1,196
Downstream					
GS Caltex Corporation	2,176	1,984	316	320	296
Caspian Pipeline Consortium	990	1,014	117	101	140
Star Petroleum Refining Company Ltd.	787	709	116	81	207
Caltex Australia Ltd.	559	435	186	214	173
Colonial Pipeline Company	555	565	34	13	–
Other	1,839	1,562	358	273	143
Total Downstream	6,906	6,269	1,127	1,002	959
Chemicals					
Chevron Phillips Chemical Company LLC	2,044	1,908	697	449	334
Other	22	20	5	3	2
Total Chemicals	2,066	1,928	702	452	336
All Other					
Dynegy Inc.	254	682	68	189	86
Other	586	740	68	45	5
Total equity method	$ 17,641	$ 16,494	$ 4,255	$3,731	$2,582
Other at or below cost	911	563			
Total investments and advances	$ 18,552	$ 17,057			
Total United States	$ 4,191	$ 4,624	$ 955	$ 833	$ 588
Total International	$ 14,361	$ 12,433	$ 3,300	$2,898	$ 1,994

Descriptions of major affiliates are as follows:

Tengizchevroil Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), a joint venture formed in 1993 to develop the Tengiz and Korolev crude oil fields in Kazakhstan over a 40-year period.

Hamaca Chevron has a 30 percent interest in the Hamaca heavy oil production and upgrading project located in Venezuela's Orinoco Belt.

NOTE 12. INVESTMENTS AND ADVANCES – Continued

Petroboscan Chevron has a 39 percent interest in Petroboscan, a joint stock company formed in 2006 to operate the Boscan Field in Venezuela. Chevron previously operated the field under an operating service agreement. At December 31, 2006, the company's carrying value of its investment in Petroboscan was approximately $300 higher than the amount of underlying equity in Petroboscan's net assets.

GS Caltex Corporation Chevron owns 50 percent of GS Caltex, a joint venture with GS Holdings. The joint venture, originally formed in 1967 between the LG Group and Caltex, imports, refines and markets petroleum products and petrochemicals predominantly in South Korea.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium (CPC), which provides the critical export route for crude oil from both TCO and Karachaganak. At December 31, 2006, the company's carrying value of its investment in CPC was about $50 higher than the amount of underlying equity in CPC's net assets.

Star Petroleum Refining Company Ltd. Chevron has a 64 percent equity ownership interest in Star Petroleum Refining Company Limited (SPRC), which owns the Star Refinery in Thailand. The Petroleum Authority of Thailand owns the remaining 36 percent of SPRC.

Caltex Australia Ltd. Chevron has a 50 percent equity ownership interest in Caltex Australia Limited (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2006, the fair value of Chevron's share of CAL common stock was approximately $2,400. The aggregate carrying value of the company's investment in CAL was approximately $60 lower than the amount of underlying equity in CAL net assets.

Colonial Pipeline Company Chevron owns an approximate 23 percent equity interest in the Colonial Pipeline Company. The Colonial Pipeline system runs from Texas to New Jersey and transports petroleum products in a 13-state market. At December 31, 2006, the company's carrying value of its investment in Colonial Pipeline was approximately $590 higher than the amount of underlying equity in Colonial Pipeline's net assets.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of Chevron Phillips Chemical Company LLC (CPChem), with the other half owned by ConocoPhillips Corporation. At December 31, 2006, the company's carrying value of its investment in CPChem was approximately $80 lower than the amount of underlying equity in CPChem's net assets.

Dynegy Inc. Chevron owns a 19 percent equity interest in the common stock of Dynegy, a provider of electricity to markets and customers throughout the United States.

Investment in Dynegy Common Stock At December 31, 2006, the carrying value of the company's investment in Dynegy common stock was approximately $250. This amount was about $180 below the company's proportionate interest in Dynegy's underlying net assets. This difference is primarily the result of write-downs of the investment in 2002 for declines in the market value of the common shares below the company's carrying value that were deemed to be other than temporary. This difference has been assigned to the extent practicable to specific Dynegy assets and liabilities, based upon the company's analysis of the various factors contributing to the decline in value of the Dynegy shares. The company's equity share of Dynegy's reported earnings is adjusted quarterly when appropriate to reflect the difference between these allocated values and Dynegy's historical book values. The market value of the company's investment in Dynegy's common stock at December 31, 2006, was approximately $700.

Investment in Dynegy Preferred Stock In May 2006, the company's investment in Dynegy Series C preferred stock was redeemed at its face value of $400. Upon redemption of the preferred stock, the company recorded a before-tax gain of $130 ($87 after tax).

Dynegy Proposed Business Combination With LS Power Group Dynegy and LS Power Group, a privately held power plant investor, developer and manager, announced in September 2006 that the companies had executed a definitive agreement to combine Dynegy's assets and operations with LS Power Group's power generation portfolio and for Dynegy to acquire a 50 percent ownership interest in a development joint venture with LS Power. Upon close of the transaction, Chevron will receive the same number of shares of the new company's Class A common stock that it currently holds in Dynegy. Chevron's ownership interest in the combined company will be approximately 11 percent. The transaction is subject to specified conditions, including the affirmative vote of two-thirds of Dynegy's common shareholders and the receipt of regulatory approvals.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes $9,582, $8,824 and $7,933 with affiliated companies for 2006, 2005 and 2004, respectively. "Purchased crude oil and products" includes $4,222, $3,219 and $2,548 with affiliated companies for 2006, 2005 and 2004, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $1,297 and $1,729 due from affiliated companies at December 31, 2006 and 2005, respectively. "Accounts payable" includes $262 and $249 due to affiliated companies at December 31, 2006 and 2005, respectively.

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron's total share, which includes Chevron loans to affiliates of $3,915 at December 31, 2006.

	Affiliates			Chevron Share		
Year ended December 31	2006	2005	2004	2006	2005	2004
Total revenues	$ 73,746	$ 64,642	$ 55,152	$ 35,695	$ 31,252	$ 25,916
Income before income tax expense	10,973	7,883	5,309	5,295	4,165	3,015
Net income	7,905	6,645	4,441	4,072	3,534	2,582
At December 31						
Current assets	$ 19,769	$ 19,903	$ 16,506	$ 8,944	$ 8,537	$ 7,540
Noncurrent assets	49,896	46,925	38,104	18,575	17,747	15,567
Current liabilities	15,254	13,427	10,949	6,818	6,034	4,962
Noncurrent liabilities	24,059	26,579	22,261	3,902	4,906	4,520
Net equity	$ 30,352	$ 26,822	$ 21,400	$ 16,799	$ 15,344	$ 13,625

NOTE 13.

PROPERTIES, PLANT AND EQUIPMENT[1]

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost[2]			Depreciation Expense[3,4]		
	2006	2005	2004	2006	2005	2004	2006	2005	2004	2006	2005	2004
Upstream												
United States	$ 46,191	$ 43,390	$ 37,329	$ 16,706	$ 15,327	$ 10,047	$ 3,739	$ 2,160	$ 1,584	$ 2,374	$ 1,869	$ 1,508
International	61,281	54,497	38,721	37,730	34,311	21,192	7,290	4,897	3,090	3,888	2,804	2,180
Total Upstream	107,472	97,887	76,050	54,436	49,638	31,239	11,029	7,057	4,674	6,262	4,673	3,688
Downstream												
United States	14,553	13,832	12,826	6,741	6,169	5,611	1,109	793	482	474	461	490
International	11,036	11,235	10,843	5,233	5,529	5,443	532	453	441	551	550	572
Total Downstream	25,589	25,067	23,669	11,974	11,698	11,054	1,641	1,246	923	1,025	1,011	1,062
Chemicals												
United States	645	624	615	289	282	292	25	12	12	19	19	20
International	771	721	725	431	402	392	54	43	27	24	23	26
Total Chemicals	1,416	1,345	1,340	720	684	684	79	55	39	43	42	46
All Other[5]												
United States	3,243	3,127	2,877	1,709	1,655	1,466	270	199	314	171	186	158
International	27	20	18	19	15	15	8	4	2	5	1	3
Total All Other	3,270	3,147	2,895	1,728	1,670	1,481	278	203	316	176	187	161
Total United States	64,632	60,973	53,647	25,445	23,433	17,416	5,143	3,164	2,392	3,038	2,535	2,176
Total International	73,115	66,473	50,307	43,413	40,257	27,042	7,884	5,397	3,560	4,468	3,378	2,781
Total	$ 137,747	$ 127,446	$ 103,954	$ 68,858	$ 63,690	$ 44,458	$ 13,027	$ 8,561	$ 5,952	$ 7,506	$ 5,913	$ 4,957

[1] Includes assets acquired in connection with the acquisition of Unocal Corporation in August 2005. Refer to Note 2, beginning on page 58, for additional information.
[2] Net of dry hole expense related to prior years' expenditures of $120, $28 and $58 in 2006, 2005 and 2004, respectively.
[3] Depreciation expense includes accretion expense of $275, $187 and $93 in 2006, 2005 and 2004, respectively.
[4] Depreciation expense includes discontinued operations of $22 in 2004.
[5] Primarily mining operations, power generation businesses, real estate assets and management information systems.

NOTE 14.

ACCOUNTING FOR BUY/SELL CONTRACTS

The company adopted the accounting prescribed by EITF Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty* (Issue 04-13) on a prospective basis from April 1, 2006. Issue 04-13 requires that two or more legally separate exchange transactions with the same counterparty, including buy/sell transactions, be combined and considered as a single arrangement for purposes of applying the provisions of Accounting Principles Board Opinion No. 29, *Accounting for Nonmonetary Transactions,* when the transactions are entered into "in contemplation" of one another. In prior periods, the company accounted for buy/sell transactions in the Consolidated Statement of Income as a monetary transaction – purchases were reported as "Purchased crude oil and products"; sales were reported as "Sales and other operating revenues."

With the company's adoption of Issue 04-13, buy/sell transactions beginning in the second quarter 2006 are netted against each other on the Consolidated Statement of Income, with no effect on net income. Amounts associated with buy/sell transactions in periods prior to the second quarter 2006 are shown as a footnote to the Consolidated Statement of Income on page 51.

NOTE 15.

LITIGATION

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to approximately 75 lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners, related to the use of MTBE in certain oxygenated gasolines and the alleged seepage of MTBE into groundwater. Resolution of these actions may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future.

The company's ultimate exposure related to these lawsuits and claims is not currently determinable, but could be material to net income in any one period. The company currently does not use MTBE in the manufacture of gasoline in the United States.

RFG Patent Fourteen purported class actions were brought by consumers of reformulated gasoline (RFG) alleging that Unocal misled the California Air Resources Board into adopting standards for composition of RFG that overlapped with Unocal's undisclosed and pending patents. Eleven lawsuits are now consolidated in U.S. District Court for the Central District of California and three are consolidated in California State Court. Unocal is alleged to have monopolized, conspired and engaged in unfair methods of competition, resulting in injury to consumers of RFG. Plaintiffs in both consolidated actions seek unspecified actual and punitive damages, attorneys' fees, and interest on behalf of an alleged class of consumers who purchased "summertime" RFG in California from January 1995 through August 2005. Unocal believes it has valid defenses and intends to vigorously defend against these lawsuits. The company's potential exposure related to these lawsuits cannot currently be estimated.

NOTE 16.

TAXES

	Year ended December 31		
	2006	2005	2004
Taxes on income*			
U.S. federal			
Current	$ 2,828	$ 1,459	$ 2,246
Deferred	200	567	(290)
State and local	581	409	345
Total United States	3,609	2,435	2,301
International			
Current	11,030	7,837	5,150
Deferred	199	826	66
Total International	11,229	8,663	5,216
Total taxes on income	$ 14,838	$ 11,098	$ 7,517

*Excludes income tax expense of $100 related to discontinued operations for 2004.

In 2006, the before-tax income for U.S. operations, including related corporate and other charges, was $9,131, compared with a before-tax income of $6,733 and $7,776 in 2005 and 2004, respectively. For international operations, before-tax income was $22,845, $18,464 and $12,775 in 2006, 2005 and 2004, respectively. U.S. federal income tax expense was reduced by $116, $289 and $176 in 2006, 2005 and 2004, respectively, for business tax credits.

The reconciliation between the U.S. statutory federal income tax rate and the company's effective income tax rate is explained in the table below:

	Year ended December 31		
	2006	2005	2004
U.S. statutory federal income tax rate	35.0%	35.0%	35.0%
Effect of income taxes from international operations at rates different from the U.S. statutory rate	10.3	9.2	5.3
State and local taxes on income, net of U.S. federal income tax benefit	1.0	1.0	0.9
Prior-year tax adjustments	0.9	0.1	(1.0)
Tax credits	(0.4)	(1.1)	(0.9)
Effects of enacted changes in tax laws	0.3	–	(0.6)
Capital loss tax benefit	–	(0.1)	(2.1)
Other	(0.7)	–	–
Effective tax rate	46.4%	44.1%	36.6%

The company records its deferred taxes on a tax-jurisdiction basis and classifies those net amounts as current or noncurrent based on the balance sheet classification of the related assets or liabilities.

The reported deferred tax balances are composed of the following:

	At December 31	
	2006	2005
Deferred tax liabilities		
Properties, plant and equipment	$ 16,054	$ 14,220
Investments and other	2,137	1,469
Total deferred tax liabilities	18,191	15,689
Deferred tax assets		
Abandonment/environmental reserves	(2,925)	(2,083)
Employee benefits	(2,707)	(1,250)
Tax loss carryforwards	(1,509)	(1,113)
Capital losses	(246)	(246)
Deferred credits	(1,670)	(1,618)
Foreign tax credits	(1,916)	(1,145)
Inventory	(378)	(182)
Other accrued liabilities	(375)	(240)
Miscellaneous	(1,144)	(1,237)
Total deferred tax assets	(12,870)	(9,114)
Deferred tax assets valuation allowance	4,391	3,249
Total deferred taxes, net	$ 9,712	$ 9,824

In 2006, deferred tax liabilities increased by approximately $2,500 from the amount reported in 2005. The increase was primarily related to increased temporary differences for properties, plant and equipment.

Deferred tax assets increased by approximately $3,800 in 2006. The increase related primarily to higher pension and other benefit obligations resulting from the implementation of FAS 158, increased foreign tax credits resulting from higher crude oil prices in tax jurisdictions with high income tax rates, and increased asset retirement obligations.

The overall valuation allowance relates to foreign tax credit carryforwards, tax loss carryforwards and temporary differences for which no benefit is expected to be realized. Tax loss carryforwards exist in many international jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2007 through 2029. Foreign tax credit carryforwards of $1,916 will expire between 2009 and 2016.

At December 31, 2006 and 2005, deferred taxes were classified in the Consolidated Balance Sheet as follows:

	At December 31	
	2006	2005
Prepaid expenses and other current assets	$ (1,167)	$ (892)
Deferred charges and other assets	(844)	(547)
Federal and other taxes on income	76	1
Noncurrent deferred income taxes	11,647	11,262
Total deferred income taxes, net	$ 9,712	$ 9,824

Income taxes are not accrued for unremitted earnings of international operations that have been or are intended to be reinvested indefinitely. Undistributed earnings of international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled $21,035 at December 31, 2006. A significant majority of this amount represents earnings reinvested as part of the company's ongoing international business. It is not practicable to estimate the amount of taxes that might be payable on the eventual remittance of such earnings. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

American Jobs Creation Act of 2004 In October 2004, the American Jobs Creation Act of 2004 was passed into law. The Act provides a deduction for income from qualified domestic refining and upstream production activities, which is to be phased in from 2005 through 2010. The company expects the net effect of this provision of the Act to result in a decrease in the federal effective tax rate for 2007 to approximately 33 percent, based on current earnings levels. In the long term, the company expects that the new deduction will result in a decrease of the annual effective tax rate to about 32 percent for that category of income, based on current earnings levels.

Taxes other than on income were as follows:

	Year ended December 31		
	2006	2005	2004
United States			
Excise and other similar taxes on products and merchandise	$ 4,831	$ 4,521	$ 4,147
Import duties and other levies	32	8	5
Property and other miscellaneous taxes	475	392	359
Payroll taxes	155	149	137
Taxes on production	360	323	257
Total United States	5,853	5,393	4,905
International			
Excise and other similar taxes on products and merchandise	4,720	4,198	3,821
Import duties and other levies	9,618	10,466	10,542
Property and other miscellaneous taxes	491	535	415
Payroll taxes	75	52	52
Taxes on production	126	138	86
Total International	15,030	15,389	14,916
Total taxes other than on income*	$ 20,883	$ 20,782	$ 19,821

*Includes taxes on discontinued operations of $3 in 2004.

NOTE 17.

SHORT-TERM DEBT

	At December 31	
	2006	2005
Commercial paper*	$ 3,472	$ 4,098
Notes payable to banks and others with originating terms of one year or less	122	170
Current maturities of long-term debt	2,176	467
Current maturities of long-term capital leases	57	70
Redeemable long-term obligations		
Long-term debt	487	487
Capital leases	295	297
Subtotal	6,609	5,589
Reclassified to long-term debt	(4,450)	(4,850)
Total short-term debt	$ 2,159	$ 739

*Weighted-average interest rates at December 31, 2006 and 2005, were 5.25 percent and 4.18 percent, respectively.

Redeemable long-term obligations consist primarily of tax-exempt variable-rate put bonds that are included as current liabilities because they become redeemable at the option of the bondholders during the year following the balance sheet date.

The company periodically enters into interest rate swaps on a portion of its short-term debt. See Note 7, beginning on page 61, for information concerning the company's debt-related derivative activities.

At December 31, 2006, the company had $4,950 of committed credit facilities with banks worldwide, which permit the company to refinance short-term obligations on a long-term basis. The facilities support the company's commercial paper borrowings. Interest on borrowings under the terms of specific agreements may be based on the London Interbank Offered Rate or bank prime rate. No amounts were outstanding under these credit agreements during 2006 or at year-end.

At December 31, 2006 and 2005, the company classified $4,450 and $4,850, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital in 2007, as the company has both the intent and the ability to refinance this debt on a long-term basis.

NOTE 18.

LONG-TERM DEBT

Chevron has three "shelf" registration statements on file with the SEC that together would permit the issuance of $3,800 of debt securities pursuant to Rule 415 of the Securities Act of 1933. Total long-term debt, excluding capital leases, at December 31, 2006, was $7,405. The company's long-term debt outstanding at year-end 2006 and 2005 was as follows:

	At December 31	
	2006	2005
3.5% notes due 2007	$ 1,996	$ 1,992
3.375% notes due 2008	738	736
5.5% notes due 2009	401	406
9.75% debentures due 2020	250	250
7.327% amortizing notes due 2014[1]	213	247
8.625% debentures due 2031	199	199
8.625% debentures due 2032	199	199
7.5% debentures due 2043	198	198
8.625% debentures due 2010	150	150
8.875% debentures due 2021	150	150
8% debentures due 2032	148	148
7.09% notes due 2007	144	144
7.5% debentures due 2029	–	475
5.05% debentures due 2012	–	412
7.35% debentures due 2009	–	347
7% debentures due 2028	–	259
Fixed and floating interest rate loans due 2007 to 2009	–	194
9.125% debentures due 2006	–	167
8.25% debentures due 2006	–	129
Medium-term notes, maturing from 2017 to 2043 (7.7%)[2]	210	210
Fixed interest rate notes, maturing from 2007 to 2011 (7.4%)[2]	46	241
Other foreign currency obligations (2.2%)[2]	23	30
Other long-term debt (7.6%)[2]	66	141
Total including debt due within one year	5,131	7,424
Debt due within one year	(2,176)	(467)
Reclassified from short-term debt	4,450	4,850
Total long-term debt	$ 7,405	$ 11,807

[1] Guarantee of ESOP debt.
[2] Less than $100 individually; weighted-average interest rate at December 31, 2006.

Long-term debt of $5,131 matures as follows: 2007 – $2,176; 2008 – $805; 2009 – $428; 2010 – $185; 2011 – $50; and after 2011 – $1,487.

In the first quarter of 2006, $185 of Union Oil Company bonds were retired at maturity. In the second quarter, the company redeemed approximately $1,700 of Unocal debt and recognized a $92 before-tax gain. In October 2006, a $129 Texaco Capital Inc. bond matured. In November 2006, the company retired Union Oil Company bonds of $196.

NOTE 19.

NEW ACCOUNTING STANDARDS

EITF Issue No. 04-6, Accounting for Stripping Costs Incurred During Production in the Mining Industry (Issue 04-6) In March 2005, the FASB ratified the earlier Emerging Issues Task Force (EITF) consensus on Issue 04-6, which was adopted by the company on January 1, 2006. Stripping costs are costs of removing overburden and other waste materials to access mineral deposits. The consensus calls for stripping costs incurred once a mine goes into production to be treated as variable production costs that should be considered a component of mineral inventory cost subject to ARB No. 43, *Restatement and Revision of Accounting Research Bulletins.* Adoption of this accounting for the company's coal, oil sands and other mining operations resulted in a $19 reduction of retained earnings as of January 1, 2006.

FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109 (FIN 48) In July 2006, the FASB issued FIN 48, which became effective for the company on January 1, 2007. This interpretation clarifies the accounting for income tax benefits that are uncertain in nature. Under FIN 48, a company will recognize a tax benefit in the financial statements for an uncertain tax position only if management's assessment is that its position is "more likely than not" (i.e., a greater than 50 percent likelihood) to be upheld on audit based only on the technical merits of the tax position. This accounting interpretation also provides guidance on measurement methodology, derecognition thresholds, financial statement classification and disclosures, interest and penalties recognition, and accounting for the cumulative-effect adjustment. The new interpretation is intended to provide better financial statement comparability among companies.

Required annual disclosures include a tabular reconciliation of unrecognized tax benefits at the beginning and end of the period; the amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate; the amounts of interest and penalties recognized in the financial statements; any expected significant impacts from unrecognized tax benefits on the financial statements over the subsequent 12-month reporting period; and a description of the tax years remaining to be examined in major tax jurisdictions.

As a result of the implementation of FIN 48, the company expects to recognize an increase in the liability for unrecognized tax benefits and associated interest and penalties as of January 1, 2007. In connection with this increase in liability, the company estimates retained earnings at the beginning of 2007 will be reduced by $250 or less. The amount of the liability and impact on retained earnings will depend in part on clarification expected to be issued by the FASB related to the criteria for determining the date of ultimate settlement with a tax authority.

FASB Statement No. 157, Fair Value Measurements (FAS 157) In September 2006, the FASB issued FAS 157, which will become effective for the company on January 1, 2008. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The Statement does not require any new fair value measurements but would apply to assets and liabilities that are required to be recorded at fair value under other accounting standards. The impact, if any, to the company from the adoption of FAS 157 in 2008 will depend on the company's assets and liabilities at that time that are required to be measured at fair value.

FASB Statement No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an Amendment of FASB Statements No. 87, 88, 106 and 132(R) (FAS 158) In September 2006, the FASB issued FAS 158, which was adopted by the company on December 31, 2006. Refer to Note 21, beginning on page 72 for additional information.

NOTE 20.

ACCOUNTING FOR SUSPENDED EXPLORATORY WELLS

The company accounts for the cost of exploratory wells in accordance with FASB Statement No. 19, *Financial and Reporting by Oil and Gas Producing Companies* (FAS 19), as amended by FASB Staff Position (FSP) FAS 19-1, *Accounting for Suspended Well Costs*, which provides that exploratory well costs continue to be capitalized after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well and (b) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if an enterprise obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. FAS 19 provides a number of indicators that can assist an entity to demonstrate sufficient progress is being made in assessing the reserves and economic viability of the project.

The following table indicates the changes to the company's suspended exploratory well costs for the three years ended December 31, 2006. No capitalized exploratory well costs were charged to expense upon the 2005 adoption of FSP FAS 19-1.

	Year ended December 31		
	2006	2005	2004
Beginning balance at January 1	$ 1,109	$ 671	$ 549
Additions associated with the acquisition of Unocal	–	317	–
Additions to capitalized exploratory well costs pending the determination of proved reserves	446	290	252
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(171)	(140)	(64)
Capitalized exploratory well costs charged to expense	(121)	(6)	(66)
Other reductions*	(24)	(23)	–
Ending balance at December 31	$ 1,239	$ 1,109	$ 671

*Represent property sales and exchanges.

The following table provides an aging of capitalized well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling. The aging of the former Unocal wells is based on the date the drilling was completed, rather than Chevron's acquisition of Unocal in 2005.

	Year ended December 31		
	2006	2005	2004
Exploratory well costs capitalized for a period of one year or less	$ 332	$ 259	$ 222
Exploratory well costs capitalized for a period greater than one year	907	850	449
Balance at December 31	$ 1,239	$ 1,109	$ 671
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	44	40	22

*Certain projects have multiple wells or fields or both.

Of the $907 of exploratory well costs capitalized for a period greater than one year at December 31, 2006, $447 (23 projects) is related to projects that had drilling activities under way or firmly planned for the near future. An additional $63 (one project) had drilling activity during 2006. The $397 balance related to 20 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.

The projects for the $397 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) $99 (two projects) – development plans submitted to a government in early 2007; (b) $80 (one project) – pre-FEED (front-end engineering and design) studies are ongoing with FEED expected to commence in 2007; (c) $75 (three projects) – continued to pursue unitization opportunities on adjacent discoveries that span international boundaries; (d) $42 (one project) – finalize analysis of new seismic study to determine the development facility concept; (e) $101 – miscellaneous activities for 13 projects with smaller amounts suspended. While progress was being made on all the projects in this category, the decision on the recognition of proved reserves under SEC rules in some cases may not occur for several years because of the complexity, scale and negotiations connected with the projects. The majority of these decisions are expected to occur in the next three years.

The $907 of suspended well costs capitalized for a period greater than one year as of December 31, 2006, represents 110 exploratory wells in 44 projects. The tables below contain the aging of these costs on a well and project basis:

Aging based on drilling completion date of individual wells:	Amount	Number of wells
1994–1996	$ 27	3
1997–2001	128	33
2002–2005	752	74
Total	$ 907	110

Aging based on drilling completion date of last well in project:	Amount	Number of projects
1999–2001	$ 9	2
2002–2006	898	42
Total	$ 907	44

NOTE 21.

EMPLOYEE BENEFIT PLANS

The company has defined-benefit pension plans for many employees. The company typically prefunds defined-benefit plans as required by local regulations or in certain situations where prefunding provides economic advantages. In the United States, all qualified plans are subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. The company does not typically fund U.S. nonqualified pension plans that are not subject to funding requirements under laws and regulations because contributions to these pension plans may be less economic and investment returns may be less attractive than the company's other investment alternatives.

The company also sponsors other postretirement plans that provide medical and dental benefits, as well as life insurance for some active and qualifying retired employees. The plans are unfunded, and the company and the retirees share the costs. Medical coverage for Medicare-eligible retirees in the company's main U.S. medical plan is secondary to Medicare (including Part D) and the increase to the company contribution for retiree medical coverage is limited to no more than 4 percent per year. This contribution cap becomes effective in the year of retirement for pre-Medicare-eligible employees retiring on or after January 1, 2005. The cap was effective as of January 1, 2005, for pre-Medicare-eligible retirees retiring before that date and all Medicare-eligible retirees. Certain life insurance benefits are paid by the company, and annual contributions are based on actual plan experience.

In June 2006, the company announced changes to several of its U.S. pension and other postretirement benefit plans, primarily merging benefits under several Unocal plans into related Chevron plans. Under the plan combinations, former-Unocal employees retiring on or after July 1, 2006, received recognition for Unocal pay and service history toward benefits to be paid under the Chevron pension and postretirement benefit plans. Unocal employees who retired before July 1, 2006, and were participating in the Unocal postretirement medical plan were merged into the Chevron primary U.S. plan effective January 1, 2007. In addition, the company's contributions for Medicare-eligible retirees under the Chevron plan were increased in 2007 in conjunction with the merger of former-Unocal participants into the Chevron plan.

Effective December 31, 2006, the company implemented the recognition and measurement provisions of Financial Accounting Standards Board (FASB) Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)* (FAS 158), which requires the recognition of the overfunded or underfunded status of each of its defined benefit pension and other postretirement benefit plans as an asset or liability, with the offset to "Accumulated other comprehensive loss." In addition, Chevron recognized its share of amounts recorded by affiliated companies in "Accumulated other comprehensive loss" to reflect their adoption of FAS 158 at December 31, 2006. The following table illustrates the incremental effect of the adoption of FAS 158 on individual lines in the company's December 2006 "Consolidated Balance Sheet" after applying the additional minimum liability adjustment required by FASB Statement No. 87, *Employers' Accounting for Pensions.*

	Before Application of FAS 158*	FAS 158 Adjustments	After Application of FAS 158
Noncurrent assets – Investments and advances	$ 18,542	$ 10	$ 18,552
Noncurrent assets – Deferred charges and other assets	$ 4,794	$ (2,706)	$ 2,088
Total assets	$ 135,324	$ (2,696)	$ 132,628
Noncurrent liabilities – Noncurrent deferred income taxes	$ 12,924	$ (1,277)	$ 11,647
Noncurrent liabilities – Reserves for employee benefits	$ 3,965	$ 784	$ 4,749
Total liabilities	$ 64,186	$ (493)	$ 63,693
Accumulated other comprehensive (loss)	$ (433)	$ (2,203)	$ (2,636)
Total stockholders' equity	$ 71,138	$ (2,203)	$ 68,935

*Accounts include minimum pension liabilities of $636 ($40 for affiliates) recognized prior to application of FAS 158 at December 31, 2006. Deferred income taxes of $234 ($13 for affiliates) were recognized on the amounts reflected in "Accumulated other comprehensive loss."

The company uses a measurement date of December 31 to value its benefit plan assets and obligations. The funded status of the company's pension and other postretirement benefit plans for 2006 and 2005 is as follows:

	Pension Benefits 2006 U.S.	Pension Benefits 2006 Int'l.	Pension Benefits 2005 U.S.	Pension Benefits 2005 Int'l.	Other Benefits 2006	Other Benefits 2005
CHANGE IN BENEFIT OBLIGATION						
Benefit obligation at January 1	$ 8,594	$ 3,611	$ 6,587	$ 3,144	$ 3,252	$ 2,820
Assumption of Unocal benefit obligations	–	–	1,437	169	–	277
Service cost	234	98	208	84	35	30
Interest cost	468	214	395	199	181	164
Plan participants' contributions	–	7	1	6	134	129
Plan amendments	14	37	42	7	107	–
Actuarial loss	297	97	593	476	(102)	189
Foreign currency exchange rate changes	–	355	–	(293)	(5)	(2)
Benefits paid	(815)	(212)	(669)	(181)	(345)	(355)
Benefit obligation at December 31	8,792	4,207	8,594	3,611	3,257	3,252
CHANGE IN PLAN ASSETS						
Fair value of plan assets at January 1	7,463	2,890	5,776	2,634	–	–
Acquisition of Unocal plan assets	–	–	1,034	65	–	–
Actual return on plan assets	1,069	225	527	441	–	–
Foreign currency exchange rate changes	–	321	–	(303)	–	–
Employer contributions	224	225	794	228	211	226
Plan participants' contributions	–	7	1	6	134	129
Benefits paid	(815)	(212)	(669)	(181)	(345)	(355)
Fair value of plan assets at December 31	7,941	3,456	7,463	2,890	–	–
FUNDED STATUS AT DECEMBER 31	(851)	(751)	(1,131)	(721)	(3,257)	(3,252)
Unrecognized net actuarial loss	–	–	2,332	1,108	–	1,167
Unrecognized prior-service cost	–	–	305	89	–	(679)
Unrecognized net transitional assets	–	–	–	5	–	–
Total recognized at December 31	$ (851)	$ (751)	$ 1,506	$ 481	$ (3,257)	$ (2,764)

Amounts recognized in the Consolidated Balance Sheet for the company's pension and other postretirement benefit plans at December 31, 2005, reflected the net of cumulative employer contributions and net periodic benefit costs recognized in earnings. The 2005 amounts for noncurrent pension liabilities also included minimum pension liability adjustments, which were offset in "Accumulated other comprehensive loss" and "Deferred charges and other assets." Amounts recognized at December 31, 2006, reflected the net funded status of each of the company's defined-benefit pension and other postretirement plans presented as either a net asset (overfunded) or a liability (underfunded).

	Pension Benefits 2006 U.S.	Pension Benefits 2006 Int'l.	Pension Benefits 2005 U.S.	Pension Benefits 2005 Int'l.	Other Benefits 2006	Other Benefits 2005
Noncurrent assets – Prepaid benefit cost[1]	$ 18	$ 96	$ 1,961	$ 960	$ –	$ –
Noncurrent assets – Intangible asset[1]	–	–	12	2	–	–
Current liabilities – Accrued liabilities	(53)	(47)	(57)	(17)	(223)	(186)
Noncurrent liabilities – Reserves for employee benefit plans[2]	(816)	(800)	(833)	(528)	(3,034)	(2,578)
Accumulated other comprehensive income[3] – Minimum pension liability	–	–	423	64	–	–
Net amount recognized	$ (851)	$ (751)	$ 1,506	$ 481	$ (3,257)	$ (2,764)

[1] Noncurrent assets are recorded in "Deferred charges and other assets" on the Consolidated Balance Sheet.
[2] The company recorded additional minimum liabilities of $435 and $66 in 2005 for U.S. and international pension plans, respectively.
[3] "Accumulated other comprehensive loss" in 2005 includes deferred income taxes of $148 and $22 for U.S. and international plans, respectively. This amount is presented net of those taxes in the Consolidated Statement of Stockholders' Equity.

NOTE 21. EMPLOYEE BENEFIT PLANS – Continued

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and other postretirement plans (excludes affiliates) at the end of 2006 after adoption of FAS 158 consisted of:

	Pension Benefits 2006 U.S.	Pension Benefits 2006 Int'l.	Other Benefits 2006
Net actuarial loss	$ 1,892	$ 1,288	$ 972
Prior-service cost (credit)	272	126	(485)
Total recognized at December 31	$ 2,164	$ 1,414	$ 487

The accumulated benefit obligations for all U.S. and international pension plans were $7,987 and $3,669 respectively, at December 31, 2006, and $7,931 and $3,080, respectively, at December 31, 2005.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2006 and 2005, was:

	Pension Benefits 2006 U.S.	2006 Int'l.	2005 U.S.	2005 Int'l.
Projected benefit obligations	$ 848	$ 849	$ 2,132	$ 818
Accumulated benefit obligations	806	741	1,993	632
Fair value of plan assets	12	172	1,206	153

The components of net periodic benefit cost for 2006, 2005 and 2004 were:

	Pension Benefits 2006 U.S.	2006 Int'l.	2005 U.S.	2005 Int'l.	2004 U.S.	2004 Int'l.	Other Benefits 2006	2005	2004
Service cost	$ 234	$ 98	$ 208	$ 84	$ 170	$ 70	$ 35	$ 30	$ 26
Interest cost	468	214	395	199	326	180	181	164	164
Expected return on plan assets	(550)	(227)	(449)	(208)	(358)	(169)	–	–	–
Amortization of transitional assets	–	1	–	2	–	1	–	–	–
Amortization of prior-service costs	46	14	45	16	42	16	(86)	(91)	(47)
Recognized actuarial losses	149	69	177	51	114	69	97	93	54
Settlement losses	70	–	86	–	96	4	–	–	–
Curtailment losses	–	–	–	–	–	2	–	–	–
Special termination benefits recognition	–	–	–	–	–	1	–	–	–
Net periodic benefit cost	$ 417	$ 169	$ 462	$ 144	$ 390	$ 174	$ 227	$ 196	$ 197

Net actuarial losses recorded in "Accumulated other comprehensive income" at December 31, 2006, related to the company's U.S. pension, international pension and other postretirement benefit plans are being amortized on a straight-line basis over approximately nine, 13 and 10 years, respectively. These amortization periods represent the estimated average remaining service of employees expected to receive benefits under the plans. These losses are amortized to the extent they exceed 10 percent of the higher of the projected benefit obligation or market-related value of plan assets. The amount subject to amortization is determined on a plan-by-plan basis. During 2007, the company estimates actuarial losses of $139 and $81 will be amortized from accumulated other comprehensive income for U.S. and international pension plans, and actuarial losses of $81 will be amortized from accumulated other comprehensive income for other postretirement benefit plans.

The weighted average amortization period for recognizing prior service costs (credits) recorded at December 31, 2006, was approximately six and 13 years for U.S. and international pension plans, respectively, and seven years for other postretirement benefit plans. During 2007, the company estimates prior service costs of $46 and $17 will be amortized from accumulated other comprehensive income for U.S. and international pension plans, and prior service credits of $81 will be amortized from accumulated other comprehensive income for other postretirement benefit plans.

Assumptions The following weighted-average assumptions were used to determine benefit obligations and net periodic benefit costs for years ended December 31:

	Pension Benefits						Other Benefits		
	2006		2005		2004				
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.	2006	2005	2004
Assumptions used to determine benefit obligations									
Discount rate	5.8%	6.0%	5.5%	5.9%	5.8%	6.4%	5.8%	5.6%	5.8%
Rate of compensation increase	4.5%	6.1%	4.0%	5.1%	4.0%	4.9%	4.5%	4.0%	4.1%
Assumptions used to determine net periodic benefit cost									
Discount rate[1,2,3]	5.8%	5.9%	5.5%	6.4%	5.9%	6.8%	5.9%	5.8%	6.1%
Expected return on plan assets[1,2]	7.8%	7.4%	7.8%	7.9%	7.8%	8.3%	N/A	N/A	N/A
Rate of compensation increase[2]	4.2%	5.1%	4.0%	5.0%	4.0%	4.9%	4.2%	4.0%	4.1%

[1] Discount rate and expected rate of return on plan assets were reviewed and updated as needed on a quarterly basis for the main U.S. pension plan.
[2] The 2005 discount rate, expected return on plan assets and rate of compensation increase reflect the remeasurement of the Unocal benefit plans at July 31, 2005, due to the acquisition of Unocal.
[3] The 2006 U.S. discount rate reflects remeasurement on July 1, 2006, due to plan combinations and changes, primarily merging benefits under several Unocal plans into related Chevron plans.

Expected Return on Plan Assets The company's estimates of the long-term rate of return on pension assets is driven primarily by actual historical asset-class returns, an assessment of expected future performance, advice from external actuarial firms and the incorporation of specific asset-class risk factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the determination of the company's estimates of long-term rates of return are consistent with these studies.

There have been no changes in the expected long-term rate of return on plan assets since 2002 for U.S. plans, which account for 70 percent of the company's pension plan assets. At December 31, 2006, the estimated long-term rate of return on U.S. pension plan assets was 7.8 percent.

The market-related value of assets of the major U.S. pension plan used in the determination of pension expense was based on the market values in the three months preceding the year-end measurement date, as opposed to the maximum allowable period of five years under U.S. accounting rules. Management considers the three-month time period long enough to minimize the effects of distortions from day-to-day market volatility and still be contemporaneous to the end of the year. For other plans, market value of assets as of the measurement date is used in calculating the pension expense.

Discount Rate The discount rate assumptions used to determine U.S. and international pension and postretirement benefit plan obligations and expense reflect the prevailing rates available on high-quality, fixed-income debt instruments. At December 31, 2006, the company selected a 5.8 percent discount rate based on Moody's Aa Corporate Bond Index and a cash flow analysis that matched estimated future benefit payments to the Citigroup Pension Discount Yield Curve. The discount rates at the end of 2005 and 2004 were 5.5 percent and 5.8 percent, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2006, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 9 percent in 2007 and gradually decline to 5 percent for 2011 and beyond. For this measurement at December 31, 2005, the assumed health care cost-trend rates started with 10 percent in 2006 and gradually decline to 5 percent for 2011 and beyond. In both measurements, the annual increase to company contributions was capped at 4 percent.

Assumed health care cost-trend rates can have a significant effect on the amounts reported for retiree health care costs. The impact is mitigated by the 4 percent cap on the company's medical contributions for the primary U.S. plan. A one-percentage-point change in the assumed health care cost-trend rates would have the following effects:

	1 Percent Increase	1 Percent Decrease
Effect on total service and interest cost components	$ 8	$ (8)
Effect on postretirement benefit obligation	$ 89	$ (85)

Plan Assets and Investment Strategy The company's pension plan weighted-average asset allocations at December 31 by asset category are as follows:

	U.S.		International	
Asset Category	2006	2005	2006	2005
Equities	68%	69%	62%	60%
Fixed Income	21%	21%	37%	39%
Real Estate	10%	9%	1%	1%
Other	1%	1%	–	–
Total	100%	100%	100%	100%

The pension plans invest primarily in asset categories with sufficient size, liquidity and cost efficiency to permit investments of reasonable size. The pension plans invest in asset categories that provide diversification benefits and are easily

NOTE 21. EMPLOYEE BENEFIT PLANS - Continued

measured. To assess the plans' investment performance, long-term asset allocation policy benchmarks have been established.

For the primary U.S. pension plan, the Chevron Board of Directors has established the following approved asset allocation ranges: Equities 40–70 percent, Fixed Income 20–60 percent, Real Estate 0–15 percent and Other 0-5 percent. The significant international pension plans also have established maximum and minimum asset allocation ranges that vary by each plan. Actual asset allocation within approved ranges is based on a variety of current economic and market conditions and consideration of specific asset category risk.

Equities include investments in the company's common stock in the amount of $17 and $13 at December 31, 2006 and 2005, respectively. The "Other" asset category includes minimal investments in private-equity limited partnerships.

Cash Contributions and Benefit Payments In 2006, the company contributed $224 and $225 to its U.S. and international pension plans, respectively. In 2007, the company expects contributions to be approximately $300 and $200 to its U.S. and international pension plans, respectively. Actual contribution amounts are dependent upon plan-investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations.

The company anticipates paying other postretirement benefits of approximately $223 in 2007, as compared with $211 paid in 2006.

The following benefit payments, which include estimated future service, are expected to be paid in the next 10 years:

	Pension Benefits		Other
	U.S.	Int'l.	Benefits
2007	$ 775	$ 206	$ 223
2008	$ 755	$ 228	$ 226
2009	$ 786	$ 237	$ 228
2010	$ 821	$ 253	$ 233
2011	$ 865	$ 249	$ 239
2012–2016	$ 4,522	$ 1,475	$ 1,252

Employee Savings Investment Plan Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP).

Charges to expense for the ESIP represent the company's contributions to the plan, which are funded either through the purchase of shares of common stock on the open market or through the release of common stock held in the leveraged employee stock ownership plan (LESOP), which is discussed below. Total company matching contributions to employee accounts within the ESIP were $169, $145 and $139 in 2006, 2005 and 2004, respectively. This cost was reduced by the value of shares released from the LESOP totaling $6, $4 and $138 in 2006, 2005 and 2004, respectively. The remaining amounts, totaling $163, $141 and $1 in 2006, 2005 and 2004, respectively, represent open market purchases.

Employee Stock Ownership Plan Within the Chevron ESIP is an employee stock ownership plan (ESOP). In 1989, Chevron established a LESOP as a constituent part of the ESOP. The LESOP provides partial prefunding of the company's future commitments to the ESIP.

As permitted by American Institute of Certified Public Accountants (AICPA) Statement of Position 93-6, *Employers' Accounting for Employee Stock Ownership Plans*, the company has elected to continue its practices, which are based on AICPA Statement of Position 76-3, *Accounting Practices for Certain Employee Stock Ownership Plans*, and subsequent consensus of the EITF of the FASB. The debt of the LESOP is recorded as debt, and shares pledged as collateral are reported as "Deferred compensation and benefit plan trust" on the Consolidated Balance Sheet and the Consolidated Statement of Stockholders' Equity.

The company reports compensation expense equal to LESOP debt principal repayments less dividends received and used by the LESOP for debt service. Interest accrued on LESOP debt is recorded as interest expense. Dividends paid on LESOP shares are reflected as a reduction of retained earnings. All LESOP shares are considered outstanding for earnings-per-share computations.

Total (credits) expenses recorded for the LESOP were $(1), $94 and $(29) in 2006, 2005 and 2004, respectively, including $17, $18 and $23 of interest expense related to LESOP debt and a (credit) charge to compensation expense of $(18), $76 and $(52).

Of the dividends paid on the LESOP shares, $59, $55 and $52 were used in 2006, 2005 and 2004, respectively, to service LESOP debt. The amount in 2006 included $28 of LESOP debt service that was scheduled for payment on the first business day of January 2007 and was paid in late December 2006. Included in the 2004 amount was a repayment of debt entered into in 1999 to pay interest on the ESOP debt. Interest expense on this debt was recognized and reported as LESOP interest expense in 1999. In addition, the company made contributions in 2005 of $98 to satisfy LESOP debt service in excess of dividends received by the LESOP. No contributions were required in 2006 or 2004 as dividends received by the LESOP were sufficient to satisfy LESOP debt service.

Shares held in the LESOP are released and allocated to the accounts of plan participants based on debt service deemed to be paid in the year in proportion to the total of current year and remaining debt service. LESOP shares as of December 31, 2006 and 2005, were as follows:

Thousands	2006	2005
Allocated shares	21,827	23,928
Unallocated shares	8,316	9,163
Total LESOP shares	30,143	33,091

Benefit Plan Trusts Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2006, the trust contained 14.2 million shares of Chevron treasury stock. The company intends to continue to pay its obligations under the benefit plans. The trust will sell the shares or use the dividends from the shares to pay benefits only to the extent that the company does not pay such benefits. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held in the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

Unocal established various grantor trusts to fund obligations under some of its benefit plans, including the deferred compensation and supplemental retirement plans. At December 31, 2006 and 2005, trust assets of $98 and $130, respectively, were invested primarily in interest-earning accounts.

Management Incentive Plans Chevron has two incentive plans, the Management Incentive Plan (MIP) and the Long-Term Incentive Plan (LTIP), for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. The MIP is an annual cash incentive plan that links awards to performance results of the prior year. The cash awards may be deferred by the recipients by conversion to stock units or other investment fund alternatives. Aggregate charges to expense for MIP were $180, $155 and $147 in 2006, 2005 and 2004, respectively. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 22 below.

Other Incentive Plans The company has a program that provides eligible employees, other than those covered by MIP and LTIP, with an annual cash bonus if the company achieves certain financial and safety goals. Charges for the programs were $329, $324 and $339 in 2006, 2005 and 2004, respectively.

NOTE 22.

STOCK OPTIONS AND OTHER SHARE-BASED COMPENSATION

Effective July 1, 2005, the company adopted the provisions of Financial Accounting Standards Board (FASB) Statement No. 123R, *Share-Based Payment* (FAS 123R), for its share-based compensation plans. The company previously accounted for these plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations and disclosure requirements established by FASB Statement No. 123, *Accounting for Stock-Based Compensation* (FAS 123).

The company adopted FAS 123R using the modified prospective method and, accordingly, results for prior periods were not restated. Refer to Note 1, beginning on page 56, for the pro forma effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123 for periods prior to adoption of FAS 123R.

For 2006 and 2005, compensation expense charged against income for stock options was $125 ($81 after tax) and $65 ($42 after tax), respectively. In addition, compensation expense charged against income for stock appreciation rights, performance units and restricted stock units was $113 ($73 after tax), $59 ($39 after tax) and $65 ($42 after tax) for 2006, 2005 and 2004, respectively. There were no significant stock-based compensation costs at December 31, 2006 and 2005, that were capitalized.

Cash received from option exercises under all share-based payment arrangements for 2006, 2005 and 2004 was $444, $297 and $385, respectively. Actual tax benefits realized for the tax deductions from option exercises were $91, $71 and $49 for 2006, 2005 and 2004, respectively.

Cash paid to settle performance units and stock appreciation rights was $68, $110 and $23 for 2006, 2005 and 2004, respectively. Cash paid in 2005 included $73 for Unocal awards paid under change-in-control plan provisions.

The company presents the tax benefits of deductions from the exercise of stock options as financing cash inflows in the Consolidated Statement of Cash Flows. In the second quarter 2006, the company implemented the transition method of FASB Staff Position FAS 123R-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*, for calculating the beginning balance of the pool of excess tax benefits related to employee compensation and determining the subsequent impact on the pool of employee awards that were fully vested and outstanding upon the adoption of FAS 123R. The company's reported tax expense for the period subsequent to the implementation of FAS 123R was not affected by this election. Refer to Note 3, beginning on page 59, for information on excess tax benefits reported on the company's Statement of Cash Flows.

In the discussion below, the references to share price and number of shares have been adjusted for the two-for-one stock split in September 2004.

Chevron Long-Term Incentive Plan (LTIP) Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, restricted stock units, stock appreciation rights, performance units and non-stock grants. From April 2004 through January 2014, no more than 160 million shares may be issued under the LTIP, and no more than

NOTE 22. STOCK OPTIONS AND OTHER SHARE-BASED COMPENSATION – Continued

64 million of those shares may be in a form other than a stock option, stock appreciation right or award requiring full payment for shares by the award recipient.

Stock options and stock appreciation rights granted under the LTIP extend for 10 years from grant date. Effective with options granted in June 2002, one-third of each award vests on the first, second and third anniversaries of the date of grant. Prior to this change, options granted by Chevron vested one year after the date of grant. Performance units granted under the LTIP settle in cash at the end of a three-year performance period. Settlement amounts are based on achievement of performance targets relative to major competitors over the period, and payments are indexed to the company's stock price.

Texaco Stock Incentive Plan (Texaco SIP) On the closing of the acquisition of Texaco in October 2001, outstanding options granted under the Texaco SIP were converted to Chevron options. These options retained a provision for being restored, which enables a participant who exercises a stock option to receive new options equal to the number of shares exchanged or who has shares withheld to satisfy tax withholding obligations to receive new options equal to the number of shares exchanged or withheld. The restored options are fully exercisable six months after the date of grant, and the exercise price is the market value of the common stock on the day the restored option is granted. Apart from the restored options, no further awards may be granted under the former Texaco plans.

Unocal Share-Based Plans (Unocal Plans) On the closing of the acquisition of Unocal in August 2005, outstanding stock options and stock appreciation rights granted under various Unocal Plans were exchanged for fully vested Chevron options and appreciation rights at a conversion ratio of 1.07 Chevron shares for each Unocal share. These awards retained the same provisions as the original Unocal Plans. Awards issued prior to 2004 generally may be exercised for up to three years after termination of employment (depending upon the terms of the individual award agreements) or the original expiration date, whichever is earlier. Awards issued since 2004 generally remain exercisable until the end of the normal option term if termination of employment occurs prior to August 10, 2007. Other awards issued under the Unocal Plans, including restricted stock, stock units, restricted stock units and performance shares, became vested at the acquisition date, and shares or cash were issued to recipients in accordance with change-in-control provisions of the plans.

The fair market values of stock options and stock appreciation rights granted in 2006, 2005 and 2004 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2006	2005	2004
Chevron LTIP			
Expected term in years[1]	6.4	6.4	7.0
Volatility[2]	23.7%	24.5%	16.5%
Risk-free interest rate based on zero coupon U.S. treasury note	4.7%	3.8%	4.4%
Dividend yield	3.1%	3.4%	3.7%
Weighted-average fair value per option granted	$ 12.74	$ 11.66	$ 7.14
Texaco SIP			
Expected term in years[1]	2.2	2.1	2.0
Volatility[2]	19.6%	18.6%	17.8%
Risk-free interest rate based on zero coupon U.S. treasury note	4.8%	3.8%	2.5%
Dividend yield	3.3%	3.4%	3.8%
Weighted-average fair value per option granted	$ 7.72	$ 6.09	$ 4.00
Unocal Plans[3]			
Expected term in years[1]	–	4.2	–
Volatility[2]	–	21.6%	–
Risk-free interest rate based on zero coupon U.S. treasury note	–	3.9%	–
Dividend yield	–	3.4%	–
Weighted-average fair value per option granted	–	$ 21.48	–

[1] Expected term is based on historical exercise and post-vesting cancellation data.
[2] Volatility rate is based on historical stock prices over an appropriate period, generally equal to the expected term.
[3] Represents options converted at the acquisition date.

A summary of option activity during 2006 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2006	59,524	$ 45.32		
Granted	9,248	$ 56.64		
Exercised	(14,921)	$ 46.11		
Restored	4,002	$ 64.13		
Forfeited	(1,908)	$ 57.09		
Outstanding at December 31, 2006	55,945	$ 47.91	6.0 yrs.	$ 1,433
Exercisable at December 31, 2006	37,063	$ 43.56	5.1 yrs.	$ 1,111

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2006, 2005 and 2004 was $281, $258 and $129, respectively.

At adoption of FAS 123R, the company elected to amortize newly issued graded awards on a straight-line basis over the requisite service period. In accordance with FAS 123R implementation guidance issued by the staff of the Securities and Exchange Commission, the company accelerates the vesting period for retirement-eligible employees in accordance with vesting provisions of the company's share-based compensation programs for awards issued after adoption of FAS 123R. As of December 31, 2006, there was $99 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted or restored under the plans. That cost is expected to be recognized over a weighted-average period of 2.0 years.

At January 1, 2006, the number of LTIP performance units outstanding was equivalent to 2,346,016 shares. During 2006, 709,200 units were granted, 827,450 units vested with cash proceeds distributed to recipients, and 117,570 units were forfeited. At December 31, 2006, units outstanding were 2,110,196, and the fair value of the liability recorded for these instruments was $113. In addition, outstanding stock appreciation rights that were awarded under various LTIP and former Texaco and Unocal programs totaled approximately 700,000 equivalent shares as of December 31, 2006. A liability of $16 was recorded for these awards.

Broad-Based Employee Stock Options In addition to the plans described above, Chevron granted all eligible employees stock options or equivalents in 1998. The options vested after two years, in February 2000, and expire after 10 years, in February 2008. A total of 9,641,600 options were awarded with an exercise price of $38.16 per share.

The fair value of each option on the date of grant was estimated at $9.54 using the Black-Scholes model for the preceding 10 years. The assumptions used in the model, based on a 10-year average, were: a risk-free interest rate of 7 percent, a dividend yield of 4.2 percent, an expected life of seven years and a volatility of 24.7 percent.

At January 1, 2006, the number of broad-based employee stock options outstanding was 1,682,904. During 2006, exercises of 354,845 shares and forfeitures of 22,000 shares reduced outstanding options to 1,306,059. As of December 31, 2006, these instruments had an aggregate intrinsic value of $46 and the remaining contractual term of these options was 1.1 years. The total intrinsic value of these options exercised during 2006, 2005 and 2004 was $10, $9 and $16, respectively.

NOTE 23.

OTHER CONTINGENCIES AND COMMITMENTS

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. The U.S. federal income tax liabilities have been settled through 1996 for Chevron Corporation, 1997 for Unocal Corporation (Unocal) and 2001 for Texaco Corporation (Texaco). California franchise tax liabilities have been settled through 1991 for Chevron, 1998 for Unocal and 1987 for Texaco. Settlement of open tax years, as well as tax issues in other countries where the company conducts its businesses, is not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Guarantees At December 31, 2006, the company and its subsidiaries provided guarantees, either directly or indirectly, of $296 for notes and other contractual obligations of affiliated companies and $131 for third parties, as described by major category below. There are no amounts being carried as liabilities for the company's obligations under these guarantees.

The $296 in guarantees provided to affiliates related to borrowings for capital projects. These guarantees were undertaken to achieve lower interest rates and generally cover the construction periods of the capital projects. Included in these amounts are the company's guarantees of $214 associated with a construction completion guarantee for the debt financing of the company's equity interest in the Baku-Tbilisi-Ceyhan (BTC) crude oil pipeline project. Substantially all of the $296 guaranteed will expire between 2007 and 2011, with the remaining expiring by the end of 2015. Under the terms of the guarantees, the company would be required to fulfill the guarantee should an affiliate be in default of its loan terms, generally for the full amounts disclosed.

The $131 in guarantees provided on behalf of third parties related to construction loans to governments of certain of the company's international upstream operations. Substantially all of the $131 in guarantees expire by 2011, with the remainder expiring by 2015. The company would be required to perform under the terms of the guarantees should an entity be in default of its loan or contract terms, generally for the full amounts disclosed.

At December 31, 2006, Chevron also had outstanding guarantees for about $120 of Equilon debt and leases. Following the February 2002 disposition of its interest in Equilon, the company received an indemnification from Shell for any claims arising from the guarantees. The company has not recorded a liability for these guarantees. Approximately 50 percent of the amounts guaranteed will expire within the 2007 through 2011 period, with the guarantees of the remaining amounts expiring by 2019.

Indemnifications The company provided certain indemnities of contingent liabilities of Equilon and Motiva to Shell and Saudi Refining, Inc., in connection with the February 2002 sale of the company's interests in those investments. The company would be required to perform if the indemnified liabilities become actual losses. Were that to occur, the company could be required to make future payments up to $300.

NOTE 23. OTHER CONTINGENCIES AND COMMITMENTS – Continued

Through the end of 2006, the company paid approximately $48 under these indemnities and continues to be obligated for possible additional indemnification payments in the future.

The company has also provided indemnities relating to contingent environmental liabilities related to assets originally contributed by Texaco to the Equilon and Motiva joint ventures and environmental conditions that existed prior to the formation of Equilon and Motiva or that occurred during the period of Texaco's ownership interest in the joint ventures. In general, the environmental conditions or events that are subject to these indemnities must have arisen prior to December 2001. Claims relating to Equilon indemnities must be asserted either as early as February 2007, or no later than February 2009, and claims relating to Motiva indemnities must be asserted either as early as February 2007, or no later than February 2012. Under the terms of these indemnities, there is no maximum limit on the amount of potential future payments. The company has not recorded any liabilities for possible claims under these indemnities. The company posts no assets as collateral and has made no payments under the indemnities.

The amounts payable for the indemnities described above are to be net of amounts recovered from insurance carriers and others and net of liabilities recorded by Equilon or Motiva prior to September 30, 2001, for any applicable incident.

In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets that were sold in 1997. Under the indemnification agreement, the company's liability is unlimited until April 2022, when the liability expires. The acquirer shares in certain environmental remediation costs up to a maximum obligation of $200, which had not been reached as of December 31, 2006.

Securitization The company securitizes certain retail and trade accounts receivable in its downstream business through the use of qualifying Special Purpose Entities (SPEs). At December 31, 2006, approximately $1,200, representing about 7 percent of Chevron's total current accounts and notes receivables balance, were securitized. Chevron's total estimated financial exposure under these securitizations at December 31, 2006, was approximately $80. These arrangements have the effect of accelerating Chevron's collection of the securitized amounts. In the event that the SPEs experience major defaults in the collection of receivables, Chevron believes that it would have no loss exposure connected with third-party investments in these securitizations.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain other contingent liabilities relating to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2007 – $3,200; 2008 – $1,700; 2009 – $2,100; 2010 – $1,900; 2011 – $900; 2012 and after – $4,100. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $3,000 in 2006, $2,100 in 2005 and $1,600 in 2004.

Minority Interests The company has commitments of $209 related to minority interests in subsidiary companies.

Environmental The company is subject to loss contingencies pursuant to environmental laws and regulations that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including, but not limited to, federal Superfund sites and analogous sites under state laws, refineries, crude oil fields, service stations, terminals, land development areas, and mining operations, whether operating, closed or divested. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Although the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemical companies.

Chevron's environmental reserve as of December 31, 2006, was $1,441. Included in this balance were remediation activities of 242 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation by the U.S. Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws. The company's remediation reserve for these sites at year-end 2006 was $122. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's consolidated financial position or liquidity.

Of the remaining year-end 2006 environmental reserves balance of $1,319, $834 related to approximately 2,250 sites for the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals) and pipelines. The remaining $485 was associated with various sites in the international downstream ($117), upstream ($252), chemicals ($61) and other ($55). Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state or local regulations. No single remediation site at year-end 2006 had a recorded liability that was material to the company's financial position, results of operations or liquidity.

It is likely that the company will continue to incur additional liabilities, beyond those recorded, for environmental remediation relating to past operations. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Effective January 1, 2003, the company implemented FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). Under FAS 143, the fair value of a liability for an asset retirement obligation is recorded when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. The liability balance of approximately $5,800 for asset retirement obligations at year-end 2006 related primarily to upstream and mining properties. Refer to Note 24 on page 82 for a discussion of the company's Asset Retirement Obligations.

For the company's other ongoing operating assets, such as refineries and chemicals facilities, no provisions are made for exit or cleanup costs that may be required when such assets reach the end of their useful lives unless a decision to sell or otherwise abandon the facility has been made, as the indeterminate settlement dates for the asset retirements prevent estimation of the fair value of the asset retirement obligation.

Global Operations Chevron and its affiliates conduct business activities in approximately 180 countries. Besides the United States, the company and its affiliates have significant operations in the following countries: Angola, Argentina, Australia, Azerbaijan, Bangladesh, Brazil, Cambodia, Canada, Chad, China, Colombia, Democratic Republic of the Congo, Denmark, France, India, Indonesia, Kazakhstan, Myanmar, the Netherlands, Nigeria, Norway, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, Republic of the Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, Venezuela and Vietnam.

The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. As has occurred in the past, actions could be taken by governments to increase public ownership of the company's partially or wholly owned businesses or assets or to impose additional taxes or royalties on the company's operations or both.

In certain locations, governments have imposed restrictions, controls and taxes, and in others, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries. Internal unrest, acts of violence or strained relations between a government and the company or other governments may affect the company's operations. Those developments have at times significantly affected the company's related operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

Equity Redetermination For oil and gas producing operations, ownership agreements may provide for periodic reassessments of equity interests in estimated crude oil and natural gas reserves. These activities, individually or together, may result in gains or losses that could be material to earnings in any given period. One such equity redetermination process has been under way since 1996 for Chevron's interests in four producing zones at the Naval Petroleum Reserve at Elk Hills, California, for the time when the remaining interests in these zones were owned by the U.S. Department of Energy. A wide range remains for a possible net settlement amount for the four zones. For this range of settlement, Chevron estimates its maximum possible net before-tax liability at approximately $200, and the possible maximum net amount that could be owed to Chevron is estimated at about

$150. The timing of the settlement and the exact amount within this range of estimates are uncertain.

Other Contingencies Chevron receives claims from and submits claims to customers; trading partners; U.S. federal, state and local regulatory bodies; governments; contractors; insurers; and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve.

The company and its affiliates also continue to review and analyze their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

NOTE 24.

ASSET RETIREMENT OBLIGATIONS

The company accounts for asset retirement obligations in accordance with Financial Accounting Standards Board Statement (FASB) No. 143, *Accounting for Asset Retirement Obligations* (FAS 143). This accounting standard applies to the fair value of a liability for an asset retirement obligation (ARO) that is recorded when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. Obligations associated with the retirement of these assets require recognition in certain circumstances: (1) the present value of a liability and offsetting asset for an ARO, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates. In 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations – An Interpretation of FASB Statement No. 143* (FIN 47), which was effective for the company on December 31, 2005. FIN 47 clarifies that the phrase "conditional asset retirement obligation," as used in FAS 143, refers to a legal obligation to perform asset retirement activity for which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the company. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Uncertainty about the timing and/or method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. FAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an ARO. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. In adopting FIN 47, the company did not recognize any additional liabilities for conditional AROs due to an inability to reasonably estimate the fair value of those obligations because of their indeterminate settlement dates.

FAS 143 and FIN 47 primarily affect the company's accounting for crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire refining, marketing and transportation (downstream) and chemical long-lived assets have been recognized, as indeterminate settlement dates for the asset retirements prevented estimation of the fair value of the associated ARO. The company performs periodic reviews of its downstream and chemical long-lived assets for any changes in facts and circumstances that might require recognition of a retirement obligation.

The following table indicates the changes to the company's before-tax asset retirement obligations in 2006, 2005 and 2004:

	2006	2005	2004
Balance at January 1	$ 4,304	$ 2,878	$ 2,856
Liabilities assumed in the Unocal acquisition	–	1,216	–
Liabilities incurred	153	90	37
Liabilities settled	(387)	(172)	(426)
Accretion expense	275	187	93
Revisions in estimated cash flows	1,428*	105	318
Balance at December 31	$ 5,773	$ 4,304	$ 2,878

*Includes $1,128 associated with estimated costs to dismantle and abandon wells and facilities damaged by the 2005 hurricanes in the Gulf of Mexico.

NOTE 25.

COMMON STOCK SPLIT

In September 2004, the company effected a two-for-one stock split in the form of a stock dividend. The total number of authorized common stock shares and associated par value were unchanged by this action. All per-share amounts in the financial statements reflect the stock split for all periods presented. The effect of the common stock split is reflected on the Consolidated Balance Sheet in "Common stock" and "Capital in excess of par value."

NOTE 26.

OTHER FINANCIAL INFORMATION

Net income in 2004 included gains of approximately $1,200 relating to the sale of nonstrategic upstream properties. Of this amount, $257 related to assets classified as discontinued operations.

Other financial information is as follows:

	Year ended December 31		
	2006	2005	2004
Total financing interest and debt costs	$ 608	$ 542	$ 450
Less: Capitalized interest	157	60	44
Interest and debt expense	$ 451	$ 482	$ 406
Research and development expenses	$ 468	$ 316	$ 242
Foreign currency effects*	$(219)	$ (61)	$ (81)

*Includes $15, $(2) and $(13) in 2006, 2005 and 2004, respectively, for the company's share of equity affiliates' foreign currency effects.

The excess of market value over the carrying value of inventories for which the Last-In, First-Out (LIFO) method is used was $6,010, $4,846 and $3,036 at December 31, 2006, 2005 and 2004, respectively. Market value is generally based on average acquisition costs for the year. LIFO profits of $82, $34 and $36 were included in net income for the years 2006, 2005 and 2004, respectively.

NOTE 27.

EARNINGS PER SHARE

Basic earnings per share (EPS) is based upon net income less preferred stock dividend requirements and includes the effects of deferrals of salary and other compensation awards that are invested in Chevron stock units by certain officers and employees of the company and the company's share of stock transactions of affiliates, which, under the applicable accounting rules, may be recorded directly to the company's retained earnings instead of net income. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company's stock option programs (refer to Note 22, "Stock Options and Other Share-Based Compensation" beginning on page 77). The table on the following page sets forth the computation of basic and diluted EPS:

NOTE 27. EARNINGS PER SHARE – Continued

	Year ended December 31		
	2006	2005	2004
BASIC EPS CALCULATION			
Income from continuing operations	$ 17,138	$ 14,099	$ 13,034
Add: Dividend equivalents paid on stock units	1	2	3
Income from continuing operations available to common stockholders	$ 17,139	$ 14,101	$ 13,037
Income from discontinued operations	–	–	294
Net income available to common stockholders – Basic	$ 17,139	$ 14,101	$ 13,331
Weighted-average number of common shares outstanding*	2,185	2,143	2,114
Add: Deferred awards held as stock units	1	1	2
Total weighted-average number of common shares outstanding	2,186	2,144	2,116
Per share of common stock			
Income from continuing operations available to common stockholders	$ 7.84	$ 6.58	$ 6.16
Income from discontinued operations	–	–	0.14
Net income – Basic	$ 7.84	$ 6.58	$ 6.30
DILUTED EPS CALCULATION			
Income from continuing operations	$ 17,138	$ 14,099	$ 13,034
Add: Dividend equivalents paid on stock units	1	2	3
Add: Dilutive effects of employee stock-based awards	–	2	1
Income from continuing operations available to common stockholders	$ 17,139	$ 14,103	$ 13,038
Income from discontinued operations	–	–	294
Net income available to common stockholders – Diluted	$ 17,139	$ 14,103	$ 13,332
Weighted-average number of common shares outstanding*	2,185	2,143	2,114
Add: Deferred awards held as stock units	1	1	2
Add: Dilutive effect of employee stock-based awards	11	11	6
Total weighted-average number of common shares outstanding	2,197	2,155	2,122
Per share of common stock			
Income from continuing operations available to common stockholders	$ 7.80	$ 6.54	$ 6.14
Income from discontinued operations	–	–	0.14
Net income – Diluted	$ 7.80	$ 6.54	$ 6.28

*Share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.

FIVE-YEAR OPERATING SUMMARY[1]

Unaudited

Worldwide – Includes Equity in Affiliates

Thousands of barrels per day, except natural gas data, which is millions of cubic feet per day	2006	2005	2004	2003	2002
UNITED STATES					
Gross production of crude oil and natural gas liquids[1]	**510**	499	555	619	665
Net production of crude oil and natural gas liquids[1]	**462**	455	505	562	602
Gross production of natural gas	**2,115**	1,860	2,191	2,619	2,945
Net production of natural gas[2]	**1,810**	1,634	1,873	2,228	2,405
Net production of oil equivalents	**763**	727	817	933	1,003
Refinery input	**939**	845	914	951	979
Sales of refined products[3]	**1,494**	1,473	1,506	1,436	1,600
Sales of natural gas liquids	**124**	151	177	194	241
Total sales of petroleum products	**1,618**	1,624	1,683	1,630	1,841
Sales of natural gas	**7,051**	5,449	4,518	4,304	5,891
INTERNATIONAL					
Gross production of crude oil and natural gas liquids[1]	**1,739**	1,676	1,645	1,681	1,765
Net production of crude oil and natural gas liquids[1]	**1,270**	1,214	1,205	1,246	1,295
Other produced volumes	**109**	143	140	114	97
Gross production of natural gas	**3,767**	2,726	2,203	2,203	2,120
Net production of natural gas[2]	**3,146**	2,599	2,085	2,064	1,971
Net production of oil equivalents	**1,904**	1,790	1,692	1,704	1,720
Refinery input	**1,050**	1,038	1,044	1,040	1,100
Sales of refined products[3,4]	**2,127**	2,252	2,368	2,274	2,148
Sales of natural gas liquids[4]	**102**	120	118	118	142
Total sales of petroleum products[4]	**2,229**	2,372	2,486	2,392	2,290
Sales of natural gas[4]	**3,478**	2,450	2,040	2,106	3,286
TOTAL WORLDWIDE					
Gross production of crude oil and natural gas liquids[1]	**2,249**	2,175	2,200	2,300	2,430
Net production of crude oil and natural gas liquids[1]	**1,732**	1,669	1,710	1,808	1,897
Other produced volumes	**109**	143	140	114	97
Gross production of natural gas	**5,882**	4,586	4,394	4,822	5,065
Net production of natural gas[2]	**4,956**	4,233	3,958	4,292	4,376
Net production of oil equivalents	**2,667**	2,517	2,509	2,637	2,723
Refinery input	**1,989**	1,883	1,958	1,991	2,079
Sales of refined products[3,4]	**3,621**	3,725	3,874	3,710	3,748
Sales of natural gas liquids[4]	**226**	271	295	312	383
Total sales of petroleum products[4]	**3,847**	3,996	4,169	4,022	4,131
Sales of natural gas[4]	**10,529**	7,899	6,558	6,410	9,177
Worldwide – Excludes Equity in Affiliates					
Number of wells completed (net)[5]					
Oil and gas	**1,575**	1,365	1,307	1,472	1,349
Dry	**32**	26	24	36	49
Productive oil and gas wells (net)[5]	**50,695**	49,508	44,707	48,155	50,320

[1] Gross production represents the company's share of total production before deducting lessors' royalties. Net production is gross production minus royalties paid to lessors.

[2] Includes natural gas consumed in operations:

	2006	2005	2004	2003	2002
United States	56	48	50	65	64
International	419	356	293	268	256
Total	475	404	343	333	320

[3] Includes volumes for buy/sell contracts (MBPD):

	2006	2005	2004	2003	2002
United States	26	88	84	90	101
International	24	129	96	104	96

[4] 2002 through 2005 conformed to the 2006 presentation.

[5] Net wells include wholly owned and the sum of fractional interests in partially owned wells. 2005 conformed to 2006 presentation.

FIVE-YEAR FINANCIAL SUMMARY

Unaudited

Millions of dollars, except per-share amounts	2006	2005	2004	2003	2002
COMBINED STATEMENT OF INCOME DATA					
REVENUES AND OTHER INCOME					
Total sales and other operating revenues	$ 204,892	$ 193,641	$ 150,865	$ 119,575	$ 98,340
Income from equity affiliates and other income	5,226	4,559	4,435	1,702	197
TOTAL REVENUES AND OTHER INCOME	210,118	198,200	155,300	121,277	98,537
TOTAL COSTS AND OTHER DEDUCTIONS	178,142	173,003	134,749	108,601	94,437
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	31,976	25,197	20,551	12,676	4,100
INCOME TAX EXPENSE	14,838	11,098	7,517	5,294	2,998
INCOME FROM CONTINUING OPERATIONS	17,138	14,099	13,034	7,382	1,102
INCOME FROM DISCONTINUED OPERATIONS	–	–	294	44	30
INCOME BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	17,138	14,099	13,328	7,426	1,132
Cumulative effect of changes in accounting principles	–	–	–	(196)	–
NET INCOME	$ 17,138	$ 14,099	$ 13,328	$ 7,230	$ 1,132
PER SHARE OF COMMON STOCK[1]					
INCOME FROM CONTINUING OPERATIONS[2]					
– Basic	$ 7.84	$ 6.58	$ 6.16	$ 3.55	$ 0.52
– Diluted	$ 7.80	$ 6.54	$ 6.14	$ 3.55	$ 0.52
INCOME FROM DISCONTINUED OPERATIONS					
– Basic	$ –	$ –	$ 0.14	$ 0.02	$ 0.01
– Diluted	$ –	$ –	$ 0.14	$ 0.02	$ 0.01
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES					
– Basic	$ –	$ –	$ –	$ (0.09)	$ –
– Diluted	$ –	$ –	$ –	$ (0.09)	$ –
NET INCOME[2]					
– Basic	$ 7.84	$ 6.58	$ 6.30	$ 3.48	$ 0.53
– Diluted	$ 7.80	$ 6.54	$ 6.28	$ 3.48	$ 0.53
CASH DIVIDENDS PER SHARE	$ 2.01	$ 1.75	$ 1.53	$ 1.43	$ 1.40
COMBINED BALANCE SHEET DATA (AT DECEMBER 31)					
Current assets	$ 36,304	$ 34,336	$ 28,503	$ 19,426	$ 17,776
Noncurrent assets	96,324	91,497	64,705	62,044	59,583
TOTAL ASSETS	132,628	125,833	93,208	81,470	77,359
Short-term debt	2,159	739	816	1,703	5,358
Other current liabilities	26,250	24,272	17,979	14,408	14,518
Long-term debt and capital lease obligations	7,679	12,131	10,456	10,894	10,911
Other noncurrent liabilities	27,605	26,015	18,727	18,170	14,968
TOTAL LIABILITIES	63,693	63,157	47,978	45,175	45,755
STOCKHOLDERS' EQUITY	$ 68,935	$ 62,676	$ 45,230	$ 36,295	$ 31,604

[1] Per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend in September 2004.
[2] The amount in 2003 includes a benefit of $0.08 for the company's share of a capital stock transaction of its Dynegy affiliate, which, under the applicable accounting rules, was recorded directly to retained earnings and not included in net income for the period.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES

Unaudited

In accordance with Statement of FAS 69, *Disclosures About Oil and Gas Producing Activities*, this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables V through VII present information on the company's estimated net proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves, and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Nigeria, Angola, Chad, Republic of the Congo and Democratic Republic of the Congo. The Asia-Pacific

TABLE I - COSTS INCURRED IN EXPLORATION, PROPERTY ACQUISITIONS AND DEVELOPMENT[1]

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
YEAR ENDED DEC. 31, 2006												
Exploration												
Wells	$ –	$ 493	$ 22	$ 515	$ 151	$ 121	$ 20	$ 246	$ 538	$ 1,053	$ 25	$ –
Geological and geophysical	–	96	8	104	180	53	12	92	337	441	–	–
Rentals and other	–	116	16	132	48	140	58	50	296	428	–	–
Total exploration	–	705	46	751	379	314	90	388	1,171	1,922	25	–
Property acquisitions												
Proved[2]	6	152	–	158	1	10	–	15	26	184	–	581
Unproved	1	47	10	58	–	1	–	135	136	194	–	–
Total property acquisitions	7	199	10	216	1	11	–	150	162	378	–	581
Development[3]	686	1,632	868	3,186	2,890	1,788	460	1,019	6,157	9,343	671	25
TOTAL COSTS INCURRED	$ 693	$ 2,536	$ 924	$ 4,153	$ 3,270	$ 2,113	$ 550	$ 1,557	$ 7,490	$ 11,643	$ 696	$ 606
YEAR ENDED DEC. 31, 2005[4]												
Exploration												
Wells	$ –	$ 452	$ 24	$ 476	$ 105	$ 38	$ 9	$ 201	$ 353	$ 829	$ –	$ –
Geological and geophysical	–	67	–	67	96	28	10	68	202	269	–	–
Rentals and other	–	93	8	101	24	58	12	72	166	267	–	–
Total exploration	–	612	32	644	225	124	31	341	721	1,365	–	–
Property acquisitions												
Proved – Unocal[2]	–	1,608	2,388	3,996	30	6,609	637	1,790	9,066	13,062	–	–
Proved – Other[2]	–	6	10	16	2	2	–	12	16	32	–	–
Unproved – Unocal	–	819	295	1,114	11	2,209	821	38	3,079	4,193	–	–
Unproved – Other	–	17	6	23	67	–	–	28	95	118	–	–
Total property acquisitions	–	2,450	2,699	5,149	110	8,820	1,458	1,868	12,256	17,405	–	–
Development[3]	507	680	601	1,788	1,892	1,088	382	726	4,088	5,876	767	43
TOTAL COSTS INCURRED	$ 507	$ 3,742	$ 3,332	$ 7,581	$ 2,227	$ 10,032	$ 1,871	$ 2,935	$ 17,065	$ 24,646	$ 767	$ 43
YEAR ENDED DEC. 31, 2004[4]												
Exploration												
Wells	$ –	$ 388	$ –	$ 388	$ 116	$ 25	$ 2	$ 127	$ 270	$ 658	$ –	$ –
Geological and geophysical	–	47	2	49	103	10	12	46	171	220	–	–
Rentals and other	–	43	3	46	52	47	1	53	153	199	–	–
Total exploration	–	478	5	483	271	82	15	226	594	1,077	–	–
Property acquisitions												
Proved[2]	–	6	1	7	111	16	–	4	131	138	–	–
Unproved	–	29	–	29	82	–	–	5	87	116	–	–
Total property acquisitions	–	35	1	36	193	16	–	9	218	254	–	–
Development[3]	413	466	375	1,254	1,057	620	403	627	2,707	3,961	896	208
TOTAL COSTS INCURRED	$ 413	$ 979	$ 381	$ 1,773	$ 1,521	$ 718	$ 418	$ 862	$ 3,519	$ 5,292	$ 896	$ 208

[1] Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. See Note 24, "Asset Retirement Obligations," on page 82.
[2] Includes wells, equipment and facilities associated with proved reserves. Does not include properties acquired through property exchanges.
[3] Includes $160, $160 and $63 costs incurred prior to assignment of proved reserves in 2006, 2005 and 2004, respectively.
[4] 2005 and 2004 presentation conformed to 2006.

geographic area includes activities principally in Australia, Azerbaijan, Bangladesh, China, Kazakhstan, Myanmar, the Partitioned Neutral Zone between Kuwait and Saudi Arabia, the Philippines, and Thailand. The international "Other" geographic category includes activities in Argentina, Brazil, Canada, Colombia, Denmark, the Netherlands, Norway, Trinidad and Tobago, Venezuela, the United Kingdom, and other countries. Amounts for TCO represent Chevron's 50 percent equity share of Tengizchevroil, an exploration and production partnership in the Republic of Kazakhstan. The affiliated companies "Other" amounts are composed of a 30 percent equity share of Hamaca, an exploration and production partnership in Venezuela and, effective October 2006, Chevron's 39 percent interest and 25 percent interest in Petroboscan and Petroindependiente, respectively. These joint stock companies are involved in the development of the Boscan and LL-652 fields in Venezuela, respectively.

TABLE II - CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
AT DEC. 31, 2006												
Unproved properties	$ 770	$ 1,007	$ 370	$ 2,147	$ 342	$ 2,373	$ 707	$ 1,082	$ 4,504	$ 6,651	$ 112	$ –
Proved properties and related producing assets	9,960	18,464	12,284	40,708	9,943	15,486	7,110	10,461	43,000	83,708	2,701	1,096
Support equipment	189	212	226	627	745	240	1,093	364	2,442	3,069	611	–
Deferred exploratory wells	–	343	7	350	231	217	149	292	889	1,239	–	–
Other uncompleted projects	370	2,188	–	2,558	4,299	1,546	493	917	7,255	9,813	2,493	40
GROSS CAP. COSTS	11,289	22,214	12,887	46,390	15,560	19,862	9,552	13,116	58,090	104,480	5,917	1,136
Unproved properties valuation	738	52	29	819	189	74	14	337	614	1,433	22	–
Proved producing properties – Depreciation and depletion	7,082	14,468	6,880	28,430	4,794	5,273	4,971	6,087	21,125	49,555	541	109
Support equipment depreciation	125	111	130	366	400	102	522	238	1,262	1,628	242	–
Accumulated provisions	7,945	14,631	7,039	29,615	5,383	5,449	5,507	6,662	23,001	52,616	805	109
NET CAPITALIZED COSTS	$ 3,344	$ 7,583	$ 5,848	$ 16,775	$ 10,177	$ 14,413	$ 4,045	$ 6,454	$ 35,089	$ 51,864	$ 5,112	$ 1,027
AT DEC. 31, 2005*												
Unproved properties	$ 769	$ 1,077	$ 397	$ 2,243	$ 407	$ 2,287	$ 645	$ 983	$ 4,322	$ 6,565	$ 108	$ –
Proved properties and related producing assets	9,546	18,283	11,467	39,296	8,404	14,928	6,613	9,627	39,572	78,868	2,264	1,213
Support equipment	204	193	230	627	715	426	1,217	356	2,714	3,341	549	–
Deferred exploratory wells	–	284	5	289	245	154	173	248	820	1,109	–	–
Other uncompleted projects	149	782	209	1,140	2,878	790	427	946	5,041	6,181	2,332	–
GROSS CAP. COSTS	10,668	20,619	12,308	43,595	12,649	18,585	9,075	12,160	52,469	96,064	5,253	1,213
Unproved properties valuation	736	90	22	848	162	69	–	318	549	1,397	17	–
Proved producing properties – Depreciation and depletion	6,818	14,067	6,049	26,934	4,266	4,016	4,105	5,720	18,107	45,041	460	90
Support equipment depreciation	140	119	149	408	317	88	680	222	1,307	1,715	213	–
Accumulated provisions	7,694	14,276	6,220	28,190	4,745	4,173	4,785	6,260	19,963	48,153	690	90
NET CAPITALIZED COSTS	$ 2,974	$ 6,343	$ 6,088	$ 15,405	$ 7,904	$ 14,412	$ 4,290	$ 5,900	$ 32,506	$ 47,911	$ 4,563	$ 1,123

*Conformed to 2006 presentation.

TABLE II - CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES - Continued

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
AT DEC. 31, 2004[1,2]												
Unproved properties	$ 769	$ 380	$ 109	$ 1,258	$ 322	$ 211	$ –	$ 970	$ 1,503	$ 2,761	$ 108	$ –
Proved properties and related producing assets	9,198	16,814	8,730	34,742	7,394	7,598	5,731	9,253	29,976	64,718	2,183	963
Support equipment	211	175	208	594	513	127	1,123	361	2,124	2,718	496	–
Deferred exploratory wells	–	225	–	225	213	81	–	152	446	671	–	–
Other uncompleted projects	91	400	169	660	2,050	605	351	391	3,397	4,057	1,749	149
GROSS CAP. COSTS	10,269	17,994	9,216	37,479	10,492	8,622	7,205	11,127	37,446	74,925	4,536	1,112
Unproved properties valuation	734	111	27	872	118	67	–	294	479	1,351	15	–
Proved producing properties – Depreciation and depletion	6,718	13,736	5,681	26,135	3,881	3,171	3,576	5,081	15,709	41,844	428	43
Support equipment depreciation	148	107	139	394	268	60	658	206	1,192	1,586	190	–
Accumulated provisions	7,600	13,954	5,847	27,401	4,267	3,298	4,234	5,581	17,380	44,781	633	43
NET CAPITALIZED COSTS	$ 2,669	$ 4,040	$ 3,369	$ 10,078	$ 6,225	$ 5,324	$ 2,971	$ 5,546	$ 20,066	$ 30,144	$ 3,903	$ 1,069

[1] Includes assets held for sale.
[2] Conformed to 2006 presentation.

TABLE III - RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES[1]

The company's results of operations from oil and gas producing activities for the years 2006, 2005 and 2004 are shown in the following table. Net income from exploration and production activities as reported on page 62 reflects income taxes computed on an effective rate basis.

In accordance with FAS 69, income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on page 62.

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
YEAR ENDED DEC. 31, 2006												
Revenues from net production												
Sales	$ 308	$ 1,845	$ 2,976	$ 5,129	$ 2,377	$ 4,938	$ 1,001	$ 2,814	$ 11,130	$ 16,259	$ 2,861	$ 598
Transfers	4,072	2,317	2,046	8,435	5,264	4,084	2,211	2,848	14,407	22,842	–	–
Total	4,380	4,162	5,022	13,564	7,641	9,022	3,212	5,662	25,537	39,101	2,861	598
Production expenses excluding taxes	(889)	(765)	(1,057)	(2,711)	(640)	(740)	(728)	(664)	(2,772)	(5,483)	(202)	(42)
Taxes other than on income	(84)	(57)	(442)	(583)	(57)	(231)	(1)	(60)	(349)	(932)	(28)	(6)
Proved producing properties: Depreciation and depletion	(275)	(1,096)	(763)	(2,134)	(579)	(1,475)	(666)	(703)	(3,423)	(5,557)	(114)	(33)
Accretion expense[2]	(11)	(80)	(39)	(130)	(26)	(30)	(23)	(49)	(128)	(258)	(1)	–
Exploration expenses	–	(407)	(24)	(431)	(296)	(209)	(110)	(318)	(933)	(1,364)	(25)	–
Unproved properties valuation	(3)	(73)	(8)	(84)	(28)	(15)	(14)	(27)	(84)	(168)	–	–
Other income (expense)[3]	1	(732)	254	(477)	(435)	(475)	50	385	(475)	(952)	8	(50)
Results before income taxes	3,119	952	2,943	7,014	5,580	5,847	1,720	4,226	17,373	24,387	2,499	467
Income tax expense	(1,169)	(357)	(1,103)	(2,629)	(4,740)	(3,224)	(793)	(2,151)	(10,908)	(13,537)	(750)	(174)
RESULTS OF PRODUCING OPERATIONS	$ 1,950	$ 595	$ 1,840	$ 4,385	$ 840	$ 2,623	$ 927	$ 2,075	$ 6,465	$ 10,850	$ 1,749	$ 293
YEAR ENDED DEC. 31, 2005												
Revenues from net production												
Sales	$ 337	$ 1,576	$ 3,174	$ 5,087	$ 2,142	$ 2,941	$ 539	$ 2,668	$ 8,290	$ 13,377	$ 2,307	$ 666
Transfers	3,497	2,127	1,395	7,019	3,615	3,179	1,986	2,607	11,387	18,406	–	–
Total	3,834	3,703	4,569	12,106	5,757	6,120	2,525	5,275	19,677	31,783	2,307	666
Production expenses excluding taxes	(916)	(638)	(777)	(2,331)	(558)	(570)	(660)	(596)	(2,384)	(4,715)	(152)	(82)
Taxes other than on income	(65)	(41)	(384)	(490)	(48)	(189)	(1)	(195)	(433)	(923)	(27)	–
Proved producing properties: Depreciation and depletion	(253)	(936)	(520)	(1,709)	(414)	(852)	(550)	(672)	(2,488)	(4,197)	(83)	(46)
Accretion expense[2]	(13)	(35)	(46)	(94)	(22)	(20)	(15)	(25)	(82)	(176)	(1)	–
Exploration expenses	–	(307)	(13)	(320)	(117)	(90)	(26)	(190)	(423)	(743)	–	–
Unproved properties valuation	(3)	(32)	(4)	(39)	(50)	(8)	–	(24)	(82)	(121)	–	–
Other income (expense)[3]	2	(354)	(140)	(492)	(243)	(182)	182	280	37	(455)	(9)	8
Results before income taxes	2,586	1,360	2,685	6,631	4,305	4,209	1,455	3,853	13,822	20,453	2,035	546
Income tax expense	(913)	(482)	(953)	(2,348)	(3,430)	(2,264)	(644)	(1,938)	(8,276)	(10,624)	(611)	(186)
RESULTS OF PRODUCING OPERATIONS	$ 1,673	$ 878	$ 1,732	$ 4,283	$ 875	$ 1,945	$ 811	$ 1,915	$ 5,546	$ 9,829	$ 1,424	$ 360

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
[2] Represents accretion of ARO liability. Refer to Note 24, "Asset Retirement Obligations," on page 82.
[3] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

TABLE III - RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES[1] - Continued

	Consolidated Companies										Affiliated Companies	
	United States				International							
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
YEAR ENDED DEC. 31, 2004												
Revenues from net production												
Sales	$ 251	$ 1,925	$ 2,163	$ 4,339	$ 1,321	$ 1,191	$ 256	$ 2,481	$ 5,249	$ 9,588	$ 1,619	$ 205
Transfers	2,651	1,768	1,224	5,643	2,645	2,265	1,613	1,903	8,426	14,069	–	–
Total	2,902	3,693	3,387	9,982	3,966	3,456	1,869	4,384	13,675	23,657	1,619	205
Production expenses excluding taxes	(710)	(547)	(697)	(1,954)	(574)	(431)	(591)	(544)	(2,140)	(4,094)	(143)	(53)
Taxes other than on income	(57)	(45)	(321)	(423)	(24)	(138)	(1)	(134)	(297)	(720)	(26)	–
Proved producing properties:												
Depreciation and depletion	(232)	(774)	(384)	(1,390)	(367)	(401)	(393)	(798)	(1,959)	(3,349)	(104)	(4)
Accretion expense[2]	(12)	(25)	(19)	(56)	(22)	(8)	(13)	11	(32)	(88)	(2)	–
Exploration expenses	–	(227)	(6)	(233)	(235)	(69)	(17)	(144)	(465)	(698)	–	–
Unproved properties valuation	(3)	(29)	(4)	(36)	(23)	(8)	–	(25)	(56)	(92)	–	–
Other income (expense)[3]	14	24	474	512	49	10	12	1,028	1,099	1,611	(7)	(58)
Results before income taxes	1,902	2,070	2,430	6,402	2,770	2,411	866	3,778	9,825	16,227	1,337	90
Income tax expense	(703)	(765)	(898)	(2,366)	(2,036)	(1,395)	(371)	(1,759)	(5,561)	(7,927)	(401)	–
RESULTS OF PRODUCING OPERATIONS	$ 1,199	$ 1,305	$ 1,532	$ 4,036	$ 734	$ 1,016	$ 495	$ 2,019	$ 4,264	$ 8,300	$ 936	$ 90

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
[2] Represents accretion of ARO liability. Refer to Note 24, "Asset Retirement Obligations," on page 82.
[3] Includes foreign currency gains and losses, gains and losses on property dispositions, and income from operating and technical service agreements.

TABLE IV - RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES - UNIT PRICES AND COSTS[1,2]

	Consolidated Companies											
	United States				International						Affiliated Companies	
	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
YEAR ENDED DEC. 31, 2006												
Average sales prices												
Liquids, per barrel	$ 55.20	$ 60.35	$ 55.80	$ 56.66	$ 61.53	$ 57.05	$ 52.23	$ 57.31	$ 57.92	$ 57.53	$ 56.80	$ 37.26
Natural gas, per thousand cubic feet	6.08	7.20	5.73	6.29	0.06	3.44	7.12	4.03	3.88	4.85	0.77	0.36
Average production costs, per barrel	10.94	9.59	9.26	9.85	5.13	3.36	11.44	5.23	5.17	6.76	3.31	2.51
YEAR ENDED DEC. 31, 2005												
Average sales prices												
Liquids, per barrel	$ 45.24	$ 48.80	$ 48.29	$ 46.97	$ 50.54	$ 45.88	$ 44.40	$ 48.61	$ 47.83	$ 47.56	$ 45.59	$ 45.89
Natural gas, per thousand cubic feet	6.94	8.43	6.90	7.43	0.04	3.59	5.74	3.31	3.48	5.18	0.61	0.26
Average production costs, per barrel	10.74	8.55	7.57	8.88	4.72	3.38	11.28	4.32	4.93	6.32	2.45	5.53
YEAR ENDED DEC. 31, 2004												
Average sales prices												
Liquids, per barrel	$ 33.43	$ 34.69	$ 34.61	$ 34.12	$ 34.85	$ 31.34	$ 31.12	$ 34.58	$ 33.33	$ 33.60	$ 30.23	$ 23.32
Natural gas, per thousand cubic feet	5.18	6.08	5.07	5.51	0.04	3.41	3.88	2.68	2.90	4.27	0.65	0.27
Average production costs, per barrel	8.14	5.26	6.65	6.60	4.89	3.50	9.69	3.47	4.67	5.43	2.31	6.10

[1] The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
[2] Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.

TABLE V - RESERVE QUANTITY INFORMATION

Reserves Governance The company has adopted a comprehensive reserves and resource classification system modeled after a system developed and approved by the Society of Petroleum Engineers, the World Petroleum Congress and the American Association of Petroleum Geologists. The system classifies recoverable hydrocarbons into six categories based on their status at the time of reporting – three deemed commercial and three noncommercial. Within the commercial classification are proved reserves and two categories of unproved, probable and possible. The noncommercial categories are also referred to as contingent resources. For reserves estimates to be classified as proved, they must meet all SEC and company standards.

Proved reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

Proved reserves are classified as either developed or undeveloped. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods.

Due to the inherent uncertainties and the limited nature of reservoir data, estimates of underground reserves are subject to change as additional information becomes available.

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the company maintains a Reserves Advisory Committee (RAC) that is chaired by the corporate reserves manager, who is a member of a corporate department that reports directly to the executive vice president responsible for the company's worldwide exploration and production activities. All of the RAC members are knowledgeable in SEC guidelines for proved reserves classification. The RAC coordinates its activities through two operating company-level reserves managers. These two reserves managers are not members of the RAC so as to preserve the corporate-level independence.

The RAC has the following primary responsibilities: provide independent reviews of the business units' recommended reserve changes; confirm that proved reserves are recognized in accordance with SEC guidelines; determine that reserve volumes are calculated using consistent and appropriate standards, procedures and technology; and maintain the *Corporate Reserves Manual*, which provides standardized procedures used corporatewide for classifying and reporting hydrocarbon reserves.

During the year, the RAC is represented in meetings with each of the company's upstream business units to review and discuss reserve changes recommended by the various asset teams. Major changes are also reviewed with the company's Strategy and Planning Committee and the Executive Committee, whose members include the Chief Executive Officer and the Chief Financial Officer. The company's annual reserve activity is also reviewed with the Board of Directors. If major changes to reserves were to occur between the annual reviews, those matters would also be discussed with the Board.

RAC subteams also conduct in-depth reviews during the year of many of the fields that have the largest proved reserves quantities. These reviews include an examination of the proved-reserve records and documentation of their alignment with the *Corporate Reserves Manual.*

Reserve Quantities At December 31, 2006, oil-equivalent reserves for the company's consolidated operations were 8.6 billion barrels. (Refer to page 24 for the definition of oil-equivalent reserves.) Approximately 28 percent of the total reserves were in the United States. For the company's interests in equity affiliates, oil-equivalent reserves were 3 billion barrels, 80 percent of which were associated with the company's 50 percent ownership in TCO. During the year, the company's Boscan and LL-652 contracts in Venezuela were converted to Empresas Mixtas (i.e., joint stock contractual structures). The company had not previously recorded any reserves for its Boscan operations, but did so this year as a result of the conversion. The conversion of LL-652 reserves was treated as the sale of consolidated company reserves and the acquisition of equity affiliate reserves.

Aside from the TCO operations, no single property accounted for more than 5 percent of company's total oil-equivalent proved reserves. Fewer than 20 other individual properties in the company's portfolio of assets each contained between 1 percent and 5 percent of the company's oil-equivalent proved reserves, which in the aggregate accounted for about 36 percent of the company's proved reserves total. These properties were geographically dispersed, located in the United States, South America, West Africa, the Middle East and the Asia-Pacific region.

In the United States, total oil-equivalent reserves at year-end 2006 were 2.4 billion barrels. Of this amount, 40 percent, 21 percent and 39 percent were located in California, the Gulf of Mexico and other U.S. areas, respectively.

In California, liquids reserves represented 95 percent of the total, with most classified as heavy oil. Because of heavy oil's high viscosity and the need to employ enhanced recovery methods, the producing operations are capital intensive in nature. Most of the company's heavy-oil fields in California employ a continuous steamflooding process.

In the Gulf of Mexico region, liquids represented approximately 64 percent of total oil-equivalent reserves. Production operations are mostly offshore and, as a result, are also capital intensive. Costs include investments in wells, production platforms and other facilities, such as gathering lines and storage facilities.

In other U.S. areas, the reserves were split about equally between liquids and natural gas. For production of crude oil, some fields utilize enhanced recovery methods, including waterflood and CO_2 injection.

The pattern of net reserve changes shown in the following tables, for the three years ending December 31, 2006, is not necessarily indicative of future trends. Apart from acquisitions, the company's ability to add proved reserves is affected by, among other things, events and circumstances that are outside the company's control, such as delays in government permitting, partner approvals of development plans, declines in oil and gas prices, OPEC constraints, geopolitical uncertainties, and civil unrest.

The company's estimated net proved underground oil and natural gas reserves and changes thereto for the years 2004, 2005 and 2006 are shown in the tables on pages 94 and 96.

TABLE V - RESERVE QUANTITY INFORMATION - Continued

NET PROVED RESERVES OF CRUDE OIL, CONDENSATE AND NATURAL GAS LIQUIDS

	Consolidated Companies											
	United States				International						Affiliated Companies	
Millions of barrels	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
RESERVES AT JAN. 1, 2004	1,051	435	572	2,058	1,923	796	807	696	4,222	6,280	1,840	479
Changes attributable to:												
Revisions	13	(68)	(2)	(57)	(70)	(43)	(36)	(12)	(161)	(218)	206	(2)
Improved recovery	28	–	6	34	34	–	6	–	40	74	–	–
Extensions and discoveries	–	8	6	14	77	9	–	17	103	117	–	–
Purchases[1]	–	2	–	2	–	–	–	–	–	2	–	–
Sales[2]	–	(27)	(103)	(130)	(16)	–	–	(33)	(49)	(179)	–	–
Production	(81)	(56)	(47)	(184)	(115)	(86)	(79)	(101)	(381)	(565)	(52)	(9)
RESERVES AT DEC. 31, 2004[3]	1,011	294	432	1,737	1,833	676	698	567	3,774	5,511	1,994	468
Changes attributable to:												
Revisions	(23)	(6)	(11)	(40)	(29)	(56)	(108)	(6)	(199)	(239)	(5)	(19)
Improved recovery	57	–	4	61	67	4	42	29	142	203	–	–
Extensions and discoveries	–	37	7	44	53	21	1	65	140	184	–	–
Purchases[1]	–	49	147	196	4	287	20	65	376	572	–	–
Sales[2]	(1)	–	(1)	(2)	–	–	–	(58)	(58)	(60)	–	–
Production	(79)	(41)	(45)	(165)	(114)	(103)	(74)	(89)	(380)	(545)	(50)	(14)
RESERVES AT DEC. 31, 2005[3]	965	333	533	1,831	1,814	829	579	573	3,795	5,626	1,939	435
Changes attributable to:												
Revisions	(14)	7	7	–	(49)	72	61	(45)	39	39	60	24
Improved recovery	49	–	3	52	13	1	6	11	31	83	–	–
Extensions and discoveries	–	25	8	33	30	6	2	36	74	107	–	–
Purchases[1]	2	2	–	4	15	–	–	2	17	21	–	119
Sales[2]	–	–	–	–	–	–	–	(15)	(15)	(15)	–	–
Production	(76)	(42)	(51)	(169)	(125)	(123)	(72)	(78)	(398)	(567)	(49)	(16)
RESERVES AT DEC. 31, 2006[3,4]	**926**	**325**	**500**	**1,751**	**1,698**	**785**	**576**	**484**	**3,543**	**5,294**	**1,950**	**562**
DEVELOPED RESERVES[5]												
At Jan. 1, 2004	832	304	515	1,651	1,059	641	588	522	2,810	4,461	1,304	140
At Dec. 31, 2004	832	192	386	1,410	990	543	490	469	2,492	3,902	1,510	188
At Dec. 31, 2005	809	177	474	1,460	945	534	439	416	2,334	3,794	1,611	196
At Dec. 31, 2006	**749**	**163**	**443**	**1,355**	**893**	**530**	**426**	**349**	**2,198**	**3,553**	**1,003**	**311**

[1] Includes reserves acquired through property exchanges.
[2] Includes reserves disposed of through property exchanges.
[3] Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 24 for the definition of a PSC). PSC-related reserve quantities are 30 percent, 29 percent and 28 percent for consolidated companies for 2006, 2005 and 2004, respectively, and 100 percent for TCO for each year.
[4] Net reserve changes (excluding production) in 2006 consist of 326 million barrels of developed reserves and (91) million barrels of undeveloped reserves for consolidated companies and (428) million barrels of developed reserves and 631 million barrels of undeveloped reserves for affiliated companies.
[5] During 2006, the percentages of undeveloped reserves at December 31, 2005, transferred to developed reserves were 11 percent and 2 percent for consolidated companies and affiliated companies, respectively.

INFORMATION ON CANADIAN OIL SANDS NET PROVED RESERVES NOT INCLUDED ABOVE:

In addition to conventional liquids and natural gas proved reserves, Chevron has significant interests in proved oil sands reserves in Canada associated with the Athabasca project. For internal management purposes, Chevron views these reserves and their development as an integral part of total upstream operations. However, SEC regulations define these reserves as mining-related and not a part of conventional oil and gas reserves. Net proved oil sands reserves were 443 million barrels as of December 31, 2006. The oil sands reserves are not considered in the standardized measure of discounted future net cash flows for conventional oil and gas reserves, which is found on page 99.

Noteworthy amounts in the categories of proved-reserve changes for 2004 through 2006 in the table above are discussed below:

Revisions In 2004, net revisions decreased reserves 218 million barrels for consolidated companies and increased reserves for affiliates by 204 million barrels. For consolidated companies, the decrease was composed of 161 million barrels for international areas and 57 million barrels for the United States. The largest downward revision internationally was 70 million barrels in Africa. One field in Angola accounted for the majority of the net decline as changes were made to oil-in-place estimates based on reservoir performance data. One field in the Asia-Pacific area essentially accounted for the 43 million-barrel downward revision for that region. The revision was associated with reduced well performance. Part of the 36 million-barrel net downward revision for Indonesia was associated with the effect of higher year-end prices on the calculation of reserves for cost-oil recovery under a production-sharing contract. In the United States, the 68 million-barrel net downward revision in the Gulf of

Mexico area was across several fields and based mainly on reservoir analyses and assessments of well performance. For affiliated companies, the 206 million-barrel increase for TCO was based on an updated assessment of reservoir performance for the Tengiz Field. Partially offsetting this increase was a downward effect of higher year-end prices on the variable royalty-rate calculation. Downward revisions also occurred in other geographic areas because of the effect of higher year-end prices on various production-sharing terms and variable royalty calculations.

In 2005, net revisions reduced reserves by 239 million and 24 million barrels for worldwide consolidated companies and equity affiliates, respectively. For consolidated companies, the net decrease was 199 million barrels in the international areas and 40 million barrels in the United States. The largest downward net revisions internationally were 108 million barrels in Indonesia and 53 million barrels in Kazakhstan, due primarily to the effect of higher year-end prices on the calculation of reserves associated with production-sharing and variable-royalty contracts. In the United States, the 40 million-barrel reduction was across many fields in each of the geographic sections. Most of the downward revision for affiliated companies was a 19 million-barrel reduction in Hamaca, attributable to revised government royalty provisions. For TCO, the downward effect of higher year-end prices was partially offset by increased reservoir performance.

In 2006, net revisions increased reserves by 39 million and 84 million barrels for worldwide consolidated companies and equity affiliates, respectively. International consolidated companies accounted for the net increase of 39 million barrels. The largest upward net revisions were 61 million barrels in Indonesia and 27 million barrels in Thailand. In Indonesia, the increase was the result of infill drilling and improved steamflood performance. The upward revision in Thailand reflected additional drilling and development activity during the year. These upward revisions were partially offset by reductions in reservoir performance in Nigeria and the United Kingdom, which decreased reserves by 43 million barrels and by 32 million barrels, respectively. Most of the upward revision for affiliated companies was related to a 60 million barrel increase in TCO as a result of improved reservoir performance.

Improved Recovery In 2006, improved recovery increased liquids volumes worldwide by 83 million barrels for consolidated companies. Reserves in the United States increased 52 million barrels, with California representing 49 million barrels of the total increase due to steamflood expansion and revised modeling activities. Internationally, improved recovery increased reserves by 31 million barrels, with no single country accounting for an increase of more than 10 million barrels.

Extensions and Discoveries In 2006, extensions and discoveries increased liquids volumes worldwide by 107 million barrels for consolidated companies. Reserves in Nigeria increased by 27 million barrels due in part to the initial booking of reserves for the Aparo Field. Additional drilling activities contributed 19 million barrels in the United Kingdom and 14 million barrels in Argentina. In the United States, the Gulf of Mexico added 25 million barrels, mainly the result of the initial booking of the Great White Field in the deepwater Perdido Fold Belt area.

Purchases In 2005, the acquisition of 572 million barrels of liquids related solely to the acquisition of Unocal in August. About three-fourths of the 376 million barrels acquired in the international areas were represented by volumes in Azerbaijan and Thailand. Most volumes acquired in the United States were in Texas and Alaska.

In 2006, acquisitions increased liquids volumes worldwide by 21 million barrels for consolidated companies and 119 million barrels for equity affiliates. For consolidated companies, the amount was mainly the result of new agreements in Nigeria, which added 13 million barrels of reserves. The other-equity-affiliates quantity reflects the result of the conversion of Boscan and LL-652 operations to joint stock companies in Venezuela.

Sales In 2004, sales of liquids volumes reduced reserves of consolidated companies by 179 million barrels. Sales totaled 130 million barrels in the United States and 33 million barrels in the "Other" international region. Sales in the "Other" region of the United States totaled 103 million barrels, with two fields accounting for approximately one-half of the volume. The 27 million barrels sold in the Gulf of Mexico reflect the sale of a number of Shelf properties. The "Other" international sales include the disposal of western Canada properties and several fields in the United Kingdom. All the sales were associated with the company's program to dispose of assets deemed nonstrategic to the portfolio of producing properties.

In 2005, sales of 58 million barrels in the "Other" international area related to the disposition of the former Unocal operations onshore in Canada.

In 2006, sales decreased reserves by 15 million barrels due to the conversion of the LL-652 risked service agreement to a joint stock company in Venezuela.

TABLE V - RESERVE QUANTITY INFORMATION - Continued

NET PROVED RESERVES OF NATURAL GAS

	Consolidated Companies											
	United States				International						Affiliated Companies	
Billions of cubic feet	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
RESERVES AT JAN. 1, 2004	323	1,841	3,189	5,353	2,642	5,373	520	3,665	12,200	17,553	2,526	112
Changes attributable to:												
Revisions	27	(391)	(316)	(680)	346	236	21	325	928	248	963	23
Improved recovery	2	–	1	3	7	–	13	–	20	23	–	–
Extensions and discoveries	1	54	89	144	16	39	2	13	70	214	–	–
Purchases[1]	–	5	–	5	–	4	–	–	4	9	–	–
Sales[2]	–	(147)	(289)	(436)	–	–	–	(111)	(111)	(547)	–	–
Production	(39)	(298)	(348)	(685)	(32)	(247)	(54)	(354)	(687)	(1,372)	(76)	(1)
RESERVES AT DEC. 31, 2004[3]	314	1,064	2,326	3,704	2,979	5,405	502	3,538	12,424	16,128	3,413	134
Changes attributable to:												
Revisions	21	(15)	(15)	(9)	211	(428)	(31)	243	(5)	(14)	(547)	49
Improved recovery	8	–	–	8	13	–	–	31	44	52	–	–
Extensions and discoveries	–	68	99	167	25	118	5	55	203	370	–	–
Purchases[1]	–	269	899	1,168	5	3,962	247	274	4,488	5,656	–	–
Sales[2]	–	–	(6)	(6)	–	–	–	(248)	(248)	(254)	–	–
Production	(39)	(215)	(350)	(604)	(42)	(434)	(77)	(315)	(868)	(1,472)	(79)	(2)
RESERVES AT DEC. 31, 2005[3]	304	1,171	2,953	4,428	3,191	8,623	646	3,578	16,038	20,466	2,787	181
Changes attributable to:												
Revisions	32	40	(102)	(30)	34	400	38	39	511	481	26	–
Improved recovery	5	–	–	5	3	–	–	5	8	13	–	–
Extensions and discoveries	–	111	157	268	11	510	–	10	531	799	–	–
Purchases[1]	6	13	–	19	–	16	–	–	16	35	–	54
Sales[2]	–	–	(1)	(1)	–	–	–	(148)	(148)	(149)	–	–
Production	(37)	(241)	(383)	(661)	(33)	(629)	(110)	(302)	(1,074)	(1,735)	(70)	(4)
RESERVES AT DEC. 31, 2006[3,4]	**310**	**1,094**	**2,624**	**4,028**	**3,206**	**8,920**	**574**	**3,182**	**15,882**	**19,910**	**2,743**	**231**
DEVELOPED RESERVES[5]												
At Jan. 1, 2004	265	1,572	2,964	4,801	954	3,627	223	3,043	7,847	12,648	1,789	52
At Dec. 31, 2004	252	937	2,191	3,380	1,108	3,701	271	2,273	7,353	10,733	2,584	63
At Dec. 31, 2005	251	977	2,794	4,022	1,346	4,819	449	2,453	9,067	13,089	2,314	85
At Dec. 31, 2006	**250**	**873**	**2,434**	**3,557**	**1,306**	**4,751**	**377**	**1,912**	**8,346**	**11,903**	**1,412**	**144**

[1] Includes reserves acquired through property exchanges.
[2] Includes reserves disposed of through property exchanges.
[3] Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page 24 for the definition of a PSC). PSC-related reserve quantities are 47 percent, 44 percent and 33 percent for consolidated companies for 2006, 2005 and 2004, respectively, and 100 percent for TCO for each year.
[4] Net reserve changes (excluding production) in 2006 consist of 549 billion cubic feet of developed reserves and 630 billion cubic feet of undeveloped reserves for consolidated companies and (769) billion cubic feet of developed reserves and 849 billion cubic feet of undeveloped reserves for affiliated companies.
[5] During 2005, the percentages of undeveloped reserves at December 31, 2004, transferred to developed reserves were 5 percent and 2 percent for consolidated companies and affiliated companies, respectively.

Noteworthy amounts in the categories of proved-reserve changes for 2004 through 2006 in the table above are discussed below:

Revisions In 2004, revisions increased reserves for consolidated companies by a net 248 billion cubic feet (BCF), composed of increases of 928 BCF internationally and decreases of 680 BCF in the United States. Internationally, about half of the 346 BCF increase in Africa related to properties in Nigeria, for which changes were associated with well performance reviews, development drilling and lease fuel calculations. The 236 BCF addition in the Asia-Pacific region was related primarily to reservoir analysis for a single field. Most of the 325 BCF in the "Other" international area was related to a new gas sales contract in Trinidad and Tobago. In the United States, the net 391 BCF downward revision in the Gulf of Mexico was related to well-performance reviews and technical analyses in several fields. Most of the net 316 BCF negative revision in the "Other" U.S. area related to two coal bed methane fields in the Mid-Continent region and their associated wells' performance. The 963 BCF increase for TCO was connected with updated analyses of reservoir performance and processing plant yields.

In 2005, reserves were revised downward by 14 BCF for consolidated companies and 498 BCF for equity affiliates. For consolidated companies, negative revisions were 428 BCF in the Asia-Pacific region. Most of the decrease was attributable to one field in Kazakhstan, due mainly to the effects of higher year-end prices on variable-royalty provisions of the production-sharing contract. Reserves additions for consolidated companies totaled 211 BCF and 243 BCF in Africa and "Other," respectively. The majority of the African region changes were in Angola, due to a revised forecast of fuel gas usage, and in Nigeria, from improved reservoir performance. The availability of third-party compression in Colombia accounted for most of the increase in the "Other" region. Revisions in the United States decreased reserves by 9 BCF, as nominal increases in the San Joaquin Valley were more than offset by decreases in the Gulf of Mexico and "Other" region. For the TCO affiliate in Kazakhstan, a reduction of 547 BCF reflects the updated forecast of future royalties payable and year-end price effects, partially offset by volumes added as a result of an updated assessment of reservoir performance.

In 2006, revisions accounted for a net increase of 481 BCF for consolidated companies and 26 BCF for affiliates. For consolidated companies, net increases of 511 BCF internationally were partially offset by a 30 BCF downward revision in the United States. Drilling and development activities added 337 BCF of reserves in Thailand, while Kazakhstan added 200 BCF, largely due to development activity. Trinidad and Tobago increased 185 BCF, attributable to improved reservoir performance and a new contract for sales of natural gas. These additions were partially offset by downward revisions of 224 BCF in the United Kingdom and 130 BCF in Australia due to drilling results and reservoir performance. U.S. "Other" had a downward revision of 102 BCF due to reservoir performance, which was partially offset by upward revisions of 72 BCF in the Gulf of Mexico and California related to reservoir performance and development drilling. TCO had an upward revision of 26 BCF associated with additional development activity and updated reservoir performance.

Extensions and Discoveries In 2004, extensions and discoveries accounted for an increase of 214 BCF, reflecting an increase in the United States of 144 BCF, with 89 BCF added in the "Other" region and 54 BCF added in the Gulf of Mexico through drilling activities in a large number of fields.

In 2005, consolidated companies increased reserves by 370 BCF, including 167 BCF in the United States and 118 BCF in the Asia-Pacific region. In the United States, 99 BCF was added in the "Other" region and 68 BCF in the Gulf of Mexico, primarily due to drilling activities. The addition in Asia-Pacific resulted primarily from increased drilling in Kazakhstan.

In 2006, extensions and discoveries accounted for an increase of 799 BCF for consolidated companies, reflecting a 531 BCF increase outside the United States and a U.S. increase of 268 BCF. Bangladesh added 451 BCF, the result of development activity and field extensions, and Thailand added 59 BCF, the result of drilling activities. U.S. "Other" contributed 157 BCF, approximately half of which was related to the South Texas and the Piceance Basin, and the Gulf of Mexico added 111 BCF, partly due to the initial booking of reserves at the Great White Field in the deepwater Perdido Fold Belt area.

Purchases In 2005, all except 7 BCF of the 5,656 BCF total purchases were associated with the Unocal acquisition. International reserve acquisitions were 4,488 BCF, with Thailand accounting for about half the volumes. Other significant volumes were added in Bangladesh and Myanmar.

In 2006, acquisition of natural gas reserves were 35 BCF for consolidated companies, about evenly divided between the company's United States and international operations. Affiliated companies added 54 BCF of reserves, the result of conversion of an operating service agreement to a joint stock company in Venezuela.

Sales In 2004, sales for consolidated companies totaled 547 BCF. Of this total, 436 BCF was in the United States and 111 BCF in the "Other" international region. In the United States, "Other" region sales accounted for 289 BCF, reflecting the disposal of a large number of smaller properties, including a coal bed methane field. Gulf of Mexico sales of 147 BCF reflected the sale of Shelf properties, with four fields accounting for more than one-third of the total sales. Sales in the "Other" international region reflected the disposition of the properties in western Canada and the United Kingdom.

In 2005, sales of 248 BCF in the "Other" international region related to the disposition of former-Unocal's onshore properties in Canada.

In 2006, sales for consolidated companies totaled 149 BCF, mostly associated with the conversion of a risked service agreement to a joint stock company in Venezuela.

TABLE VI - STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES

The standardized measure of discounted future net cash flows, related to the preceding proved oil and gas reserves, is calculated in accordance with the requirements of FAS 69. Estimated future cash inflows from production are computed by applying year-end prices for oil and gas to year-end quantities of estimated net proved reserves. Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions, and include estimated costs for asset retirement obligations. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pretax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10 percent midperiod discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced.

The information provided does not represent management's estimate of the company's expected future cash flows or value of proved oil and gas reserves. Estimates of proved-reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The arbitrary valuation prescribed under FAS 69 requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and should not be relied upon as an indication of the company's future cash flows or value of its oil and gas reserves. In the following table, "Standardized Measure Net Cash Flows" refers to the standardized measure of discounted future net cash flows.

TABLE VI - STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES - Continued

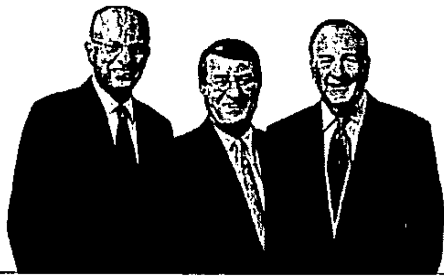
	Consolidated Companies											
	United States				International						Affiliated Companies	
Millions of dollars	Calif.	Gulf of Mexico	Other	Total U.S.	Africa	Asia-Pacific	Indonesia	Other	Total Int'l.	Total	TCO	Other
AT DECEMBER 31, 2006												
Future cash inflows from production	$ 48,828	$ 23,768	$ 38,727	$ 111,323	$ 97,571	$ 70,288	$ 30,538	$ 36,272	$ 234,669	$ 345,992	$104,069	$ 20,644
Future production costs	(14,791)	(6,750)	(12,845)	(34,386)	(12,523)	(13,398)	(16,281)	(10,777)	(52,979)	(87,365)	(7,796)	(2,348)
Future devel. costs	(3,999)	(2,947)	(1,399)	(8,345)	(9,648)	(6,963)	(2,284)	(3,082)	(21,977)	(30,322)	(7,026)	(1,732)
Future income taxes	(10,171)	(4,764)	(8,290)	(23,225)	(53,214)	(20,633)	(5,448)	(11,164)	(90,459)	(113,684)	(25,212)	(8,282)
Undiscounted future net cash flows	19,867	9,307	16,193	45,367	22,186	29,294	6,525	11,249	69,254	114,621	64,035	8,282
10 percent midyear annual discount for timing of estimated cash flows	(9,779)	(3,256)	(7,210)	(20,245)	(10,065)	(12,457)	(2,426)	(3,608)	(28,556)	(48,801)	(40,597)	(5,185)
STANDARDIZED MEASURE NET CASH FLOWS	$ 10,088	$ 6,051	$ 8,983	$ 25,122	$ 12,121	$ 16,837	$ 4,099	$ 7,641	$ 40,698	$ 65,820	$ 23,438	$ 3,097
AT DECEMBER 31, 2005												
Future cash inflows from production	$ 50,771	$ 29,422	$ 50,039	$ 130,232	$ 101,912	$ 73,612	$ 32,538	$ 44,680	$ 252,742	$ 382,974	$ 97,707	$ 20,616
Future production costs	(15,719)	(5,758)	(12,767)	(34,244)	(11,366)	(12,459)	(18,260)	(11,908)	(53,993)	(88,237)	(7,399)	(2,101)
Future devel. costs	(2,274)	(2,467)	(873)	(5,614)	(8,197)	(5,840)	(1,730)	(2,439)	(18,206)	(23,820)	(5,996)	(762)
Future income taxes	(11,092)	(7,173)	(12,317)	(30,582)	(50,894)	(21,509)	(5,709)	(13,917)	(92,029)	(122,611)	(23,818)	(6,036)
Undiscounted future net cash flows	21,686	14,024	24,082	59,792	31,455	33,804	6,839	16,416	88,514	148,306	60,494	11,717
10 percent midyear annual discount for timing of estimated cash flows	(10,947)	(4,520)	(10,838)	(26,305)	(14,881)	(14,929)	(2,269)	(5,635)	(37,714)	(64,019)	(37,674)	(7,768)
STANDARDIZED MEASURE NET CASH FLOWS	$ 10,739	$ 9,504	$ 13,244	$ 33,487	$ 16,574	$ 18,875	$ 4,570	$ 10,781	$ 50,800	$ 84,287	$ 22,820	$ 3,949
AT DECEMBER 31, 2004												
Future cash inflows from production	$ 32,793	$ 19,043	$ 28,676	$ 80,512	$ 64,628	$ 35,960	$ 25,313	$ 30,061	$ 155,962	$ 236,474	$ 61,875	$ 12,769
Future production costs	(11,245)	(3,840)	(7,343)	(22,428)	(10,662)	(8,604)	(12,830)	(7,884)	(39,980)	(62,408)	(7,322)	(3,734)
Future devel. costs	(1,731)	(2,389)	(667)	(4,787)	(6,355)	(2,531)	(717)	(1,593)	(11,196)	(15,983)	(5,366)	(407)
Future income taxes	(6,706)	(4,336)	(6,991)	(18,033)	(29,519)	(9,731)	(5,354)	(9,914)	(54,518)	(72,551)	(13,895)	(2,934)
Undiscounted future net cash flows	13,111	8,478	13,675	35,264	18,092	15,094	6,412	10,670	50,268	85,532	35,292	5,694
10 percent midyear annual discount for timing of estimated cash flows	(6,656)	(2,715)	(6,110)	(15,481)	(9,035)	(6,966)	(2,465)	(3,451)	(21,917)	(37,398)	(22,249)	(3,817)
STANDARDIZED MEASURE NET CASH FLOWS	$ 6,455	$ 5,763	$ 7,565	$ 19,783	$ 9,057	$ 8,128	$ 3,947	$ 7,219	$ 28,351	$ 48,134	$ 13,043	$ 1,877

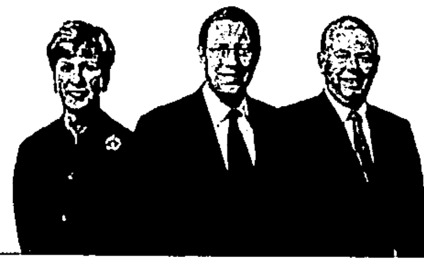
TABLE VII - CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED RESERVES

The changes in present values between years, which can be significant, reflect changes in estimated proved reserve quantities and prices and assumptions used in forecasting production volumes and costs. Changes in the timing of production are included with "Revisions of previous quantity estimates."

	Consolidated Companies			Affiliated Companies		
Millions of dollars	2006	2005	2004	2006	2005	2004
PRESENT VALUE AT JANUARY 1	$ 84,287	$ 48,134	$ 50,805	$ 26,769	$ 14,920	$ 13,118
Sales and transfers of oil and gas produced net of production costs	(32,690)	(26,145)	(18,843)	(3,180)	(2,712)	(1,602)
Development costs incurred	8,875	5,504	3,579	721	810	1,104
Purchases of reserves	580	25,307	58	1,767	–	–
Sales of reserves	(306)	(2,006)	(3,734)	–	–	–
Extensions, discoveries and improved recovery less related costs	4,067	7,446	2,678	–	–	–
Revisions of previous quantity estimates	7,277	(13,564)	1,611	(967)	(2,598)	970
Net changes in prices, development and production costs	(24,725)	61,370	6,173	(837)	19,205	266
Accretion of discount	14,218	8,160	8,139	3,673	2,055	1,818
Net change in income tax	4,237	(29,919)	(2,332)	(1,412)	(4,911)	(754)
Net change for the year	(18,467)	36,153	(2,671)	(235)	11,849	1,802
PRESENT VALUE AT DECEMBER 31	$ 65,820	$ 84,287	$ 48,134	$ 26,534	$ 26,769	$ 14,920

BOARD OF DIRECTORS





David J. O'Reilly, 60
Chairman of the Board and Chief Executive Officer since 2000. Previously he was elected a Director and Vice Chairman in 1998, President of Chevron Products Company in 1994 and a Vice President in 1991. He is a Director of the American Petroleum Institute, the Peterson Institute for International Economics and the Eisenhower Fellowships Board of Trustees. He joined Chevron in 1968.

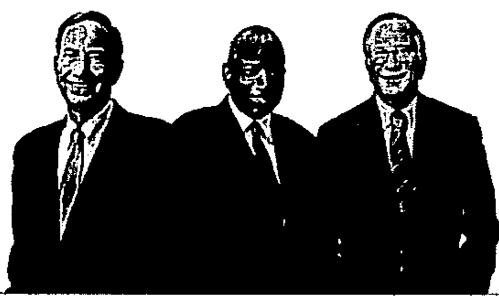
Peter J. Robertson, 60
Vice Chairman of the Board since 2002. In addition to a broad sharing of the CEO's responsibilities, he is directly responsible for Strategic Planning; Policy, Government and Public Affairs; and Human Resources. Previously he was responsible for worldwide upstream and gas operations. He is a Director of the American Petroleum Institute, the U.S.-Saudi Arabian Business Council and the U.S.-Russian Business Council, and is Chairman of the U.S. Energy Association. He joined Chevron in 1973.

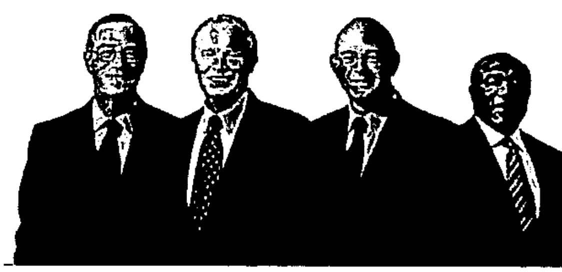
Samuel H. Armacost, 67
Lead Director since 2006 and a Director since 1982. He is Chairman of the Board of SRI International. Previously he was President, Chief Executive Officer and a Director of BankAmerica Corporation. He also is a Director of Del Monte Foods Company; Callaway Golf Company; Franklin Resources, Inc.; and Exponent, Inc. (3, 4)

Linnet F. Deily, 61
Director since 2006. She served as a Deputy U.S. Trade Representative and Ambassador to the World Trade Organization from 2001 to June 2005. Previously she was Vice Chairman of Charles Schwab Corporation. She is a Director of Alcatel-Lucent and Honeywell International Inc. (1)

Robert E. Denham, 61
Director since 2004. He is a Partner in the law firm of Munger, Tolles & Olson LLP. Previously he was Chairman and Chief Executive Officer of Salomon Inc. He also is a Director of Alcatel-Lucent; Wesco Financial Corporation; and Fomento Económico Mexicano, S.A. de C.V. (1)

Robert J. Eaton, 67
Director since 2000. He is retired Chairman of the Board of Management of DaimlerChrysler AG. Previously he was Chairman of the Board and Chief Executive Officer of Chrysler Corporation. (2, 4)





Sam Ginn, 69
Director since 1989. He is a private investor and the retired Chairman of Vodafone AirTouch, Plc. Previously he was Chairman of the Board and Chief Executive Officer of AirTouch Communications, Inc., and Chairman of the Board, President and Chief Executive Officer of Pacific Telesis Group. He is a Director of ICO Global Communications (Holdings) Limited and is a Member of the Yosemite Fund Council and the Hoover Institute Board of Overseers. (2, 3)

Franklyn G. Jenifer, 67
Director since 1993. He is President Emeritus of The University of Texas at Dallas. Previously he was President of Howard University and Chancellor of the Massachusetts Board of Regents of Higher Education. (1)

Sam Nunn, 68
Director since 1997. He is Co-Chairman and Chief Executive Officer of the Nuclear Threat Initiative, a charitable organization. He also is a distinguished professor at the Sam Nunn School of International Affairs, Georgia Tech. He served as a U.S. Senator from Georgia for 24 years. He is a Director of The Coca-Cola Company, Dell Inc. and the General Electric Company. (2, 3)

Donald B. Rice, 67
Director since 2005. He is Chairman of the Board, President and Chief Executive Officer of Agensys, Inc., a private biotechnology company. Previously he was President and Chief Operating Officer of Teledyne, Inc. He is a Director of Amgen, Inc.; Vulcan Materials Company; and Wells Fargo & Company. (2, 3)

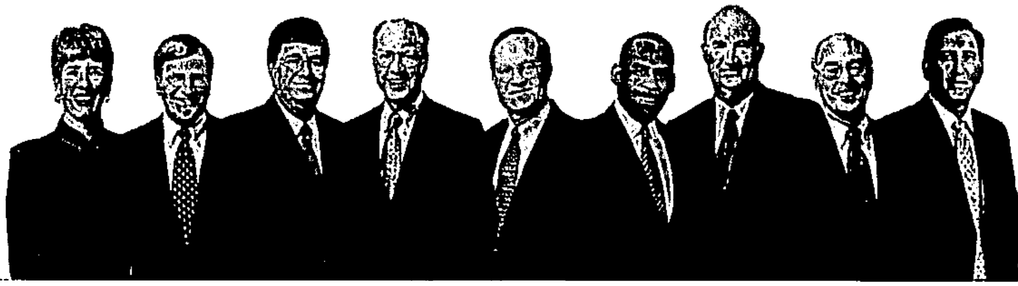
Charles R. Shoemate, 67
Director since 1998. He is retired Chairman of the Board, President and Chief Executive Officer of Bestfoods. (1)

Ronald D. Sugar, 58
Director since 2005. He is Chairman of the Board, Chief Executive Officer and President of Northrop Grumman Corporation. Previously he was President and Chief Operating Officer of Northrop Grumman. He is a Governor of the Aerospace Industries Association and a Member of the National Academy of Engineering. (2, 4)

Carl Ware, 63
Director since 2001. He was Senior Adviser to the Chief Executive Officer of The Coca-Cola Company from 2003 until 2006 after retiring as Executive Vice President of Global Public Affairs and Administration for The Coca-Cola Company. Previously he was President of The Coca-Cola Company's Africa Group. He is a Director of Coca-Cola Bottling Co. Consolidated and Cummins Inc. (3, 4)

COMMITTEES OF THE BOARD
1) Audit: Charles R. Shoemate, Chair
2) Public Policy: Sam Nunn, Chair
3) Board Nominating and Governance: Samuel H. Armacost, Chair
4) Management Compensation: Robert J. Eaton, Chair

CORPORATE OFFICERS



Lydia I. Beebe, 54
Corporate Secretary since 1995. Responsible for providing corporate governance counsel to the Board of Directors and senior management, and managing stockholder relations and subsidiary governance. Previously Senior Manager, Chevron Tax Department; Manager, Federal Tax Legislation; and Chevron Legal Representative in Washington, D.C. Joined Chevron in 1977.

John E. Bethancourt, 55
Executive Vice President, Technology and Services, since 2003. Responsible also for health, environment and safety as well as project resources, procurement, additives and coal operations. Previously the company's Vice President, Human Resources, and Texaco Corporate Vice President and President, Production Operations, Texaco Worldwide Exploration and Production. Joined the company in 1974.

Stephen J. Crowe, 59
Vice President and Chief Financial Officer since 2005. Responsible for comptroller, audit, treasury, tax and investor relations activities corporatewide. Previously Chevron Vice President and Comptroller; Vice President, Finance, Chevron Products Company; and Assistant Comptroller, Chevron Corporation. Joined Chevron in 1972.

John D. Gass, 54
Corporate Vice President and President, Chevron Global Gas, since 2003. Responsible for the company's natural gas business, shipping company, power and pipeline operations, and the Sasol Chevron gas-to-liquids joint venture. Director of Sasol Chevron and GS Caltex Corporation. Previously Managing Director, Southern Africa Strategic Business Unit, and Managing Director, Chevron Australia Pty Ltd. Joined the company in 1974.

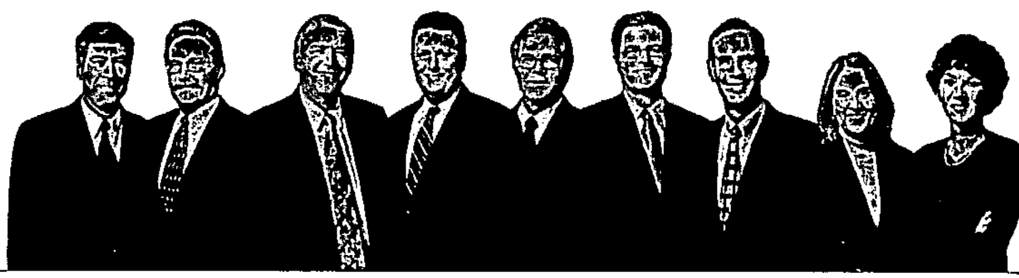
Mark A. Humphrey, 55
Vice President and Comptroller since 2005. Responsible for corporatewide accounting, financial reporting and analysis, internal controls, funded benefits investments, actuarial functions, and Finance Shared Services. Previously the company's General Manager, Finance Shared Services, and Vice President, Finance, Chevron Products Company. Joined Chevron in 1976.

Charles A. James, 52
Vice President and General Counsel since 2002. Previously Assistant Attorney General, Antitrust Division, U.S. Department of Justice, in President George W. Bush's administration, and Chair, Antitrust and Trade Regulation Practice - Jones, Day, Reavis & Pogue, Washington, D.C. Joined Chevron in 2002.

George L. Kirkland, 56
Executive Vice President, Upstream and Gas, since 2005. Responsible for global exploration, production and gas activities. Previously Corporate Vice President and President, Chevron Overseas Petroleum Inc.; President, Chevron Exploration and Production Company; and President, Chevron U.S.A. Production Company. Joined Chevron in 1974.

David M. Krattebol, 62
Vice President and Treasurer since 2000. Previously President, Chevron San Jorge; Vice President, Logistics and Trading, Chevron Products Company; Vice President, Finance, Chevron Products Company; and Vice President, Finance, Chevron Overseas Petroleum Inc. Joined Chevron in 1971.

Gary P. Luquette, 51
Corporate Vice President and President, Chevron North America Exploration and Production Company, since 2006. Previously Managing Director, Upstream Europe Strategic Business Unit, Chevron International Exploration and Production Company, and Vice President, San Joaquin Valley Business Unit, Chevron North America Exploration and Production Company. Joined Chevron in 1978.



John W. McDonald, 55
Vice President, Strategic Planning, since 2002. Responsible for advising senior management in setting the company's strategic direction, mergers and acquisitions. Previously President and Managing Director, Chevron Upstream Europe, Chevron Overseas Petroleum Inc., and Vice President, Gulf of Mexico Offshore Division, Texaco Exploration and Production Inc. Joined the company in 1975.

Donald L. Paul, 60
Vice President and Chief Technology Officer since 2001. Responsible for Chevron's three technology companies: Energy Technology, Information Technology and Technology Ventures. Previously Chevron Vice President, Technology and Environmental Affairs; President, Chevron Canada Resources; and President, Chevron Petroleum Technology Company. Joined Chevron in 1975.

Alan R. Preston, 55
Vice President, Human Resources, since 2003. Previously the company's General Manager, Global Remuneration; General Manager, Organization/Compensation, Chevron Corporation; and General Manager, Human Resources, Chevron Products Company. Joined Chevron in 1973.

Jay R. Pryor, 49
Vice President, Business Development, since May 2006. Responsible for identifying and developing new, large-scale business opportunities worldwide. Previously Managing Director, Nigeria/Mid-Africa Strategic Business Unit and Chevron Nigeria Ltd., and Managing Director, Asia South Business Unit and Chevron Offshore (Thailand) Ltd. Joined Chevron in 1979.

Thomas R. Schuttish, 59
General Tax Counsel since 2002. Responsible for guiding and directing corporatewide tax activities and managing Chevron's Tax department. Previously the company's Assistant General Tax Counsel. Joined Chevron in 1980.

John S. Watson, 50
Corporate Vice President and President, Chevron International Exploration and Production Company, since 2005. Responsible for exploration and production activities outside North America. Previously Chevron Vice President and Chief Financial Officer; Chevron Vice President, Strategic Planning; and Director, Caltex Petroleum Corporation. Joined Chevron in 1980.

Michael K. Wirth, 46
Executive Vice President, Downstream, since 2006. Responsible for worldwide refining, marketing, lubricants, and supply and trading. Previously President, Global Supply and Trading; President, Marketing, Asia/Middle East/Africa Strategic Business Unit; and President, Marketing, Caltex Corporation. Joined Chevron in 1982.

Patricia E. Yarrington, 50
Vice President, Policy, Government and Public Affairs, since 2002. Responsible for government relations, community relations and communications. Director of Chevron Phillips Chemical Company LLC. Previously Chevron Vice President, Strategic Planning; President, Chevron Canada Limited; and Comptroller, Chevron Products Company. Joined Chevron in 1980.

Rhonda I. Zygocki, 49
Vice President, Health, Environment and Safety, since 2003. Responsible for HES strategic planning and issues management, compliance and auditing, and emergency response. Previously Managing Director, Chevron Australia Pty Ltd; Adviser to the Chairman of the Board, Chevron Corporation; and Manager of Strategic Planning, Chevron Corporation. Joined Chevron in 1980.

EXECUTIVE COMMITTEE
David J. O'Reilly, Peter J. Robertson, John E. Bethancourt, Stephen J. Crowe, Charles A. James, George L. Kirkland and Michael K. Wirth. Lydia I. Beebe, Secretary.

Chevron History

1879 Incorporated in San Francisco, California, as the Pacific Coast Oil Company.

1900 Acquired by the West Coast operations of John D. Rockefeller's original Standard Oil Company.

1911 Emerged as an autonomous entity – Standard Oil Company (California) – following the U.S. Supreme Court decision to divide the Standard Oil conglomerate into 34 independent companies.

1926 Acquired Pacific Oil Company to become Standard Oil Company of California (Socal).

1936 Formed the Caltex Group of Companies, jointly owned by Socal and The Texas Company (later became Texaco), to manage exploration and production interests of the two companies in the Middle East and Indonesia and provide an outlet for crude oil through The Texas Company's European markets.

1947 Acquired Signal Oil Company, obtaining the Signal brand name and adding 2,000 retail stations in the western United States.

1961 Acquired Standard Oil Company (Kentucky), a major petroleum products marketer in five southeastern states, to provide outlets for crude oil from southern Louisiana and the U.S. Gulf of Mexico, where the company was a major producer.

1984 Acquired Gulf Corporation – nearly doubling the size of crude oil and natural gas activities – and gained significant presence in industrial chemicals, natural gas liquids and coal. Changed name to Chevron Corporation to identify with the name under which most products were marketed.

1988 Purchased Tenneco Inc.'s U.S. Gulf of Mexico crude oil and natural gas properties, becoming one of the largest U.S. natural gas producers.

1993 Formed Tengizchevroil, a joint venture with the Republic of Kazakhstan, to develop and produce the giant Tengiz Field, becoming the first major Western oil company to enter newly independent Kazakhstan.

1999 Acquired Rutherford-Moran Oil Corporation and Petrolera Argentina San Jorge S.A. These acquisitions provided inroads to Asian natural gas markets and built on the company's Latin America business foundation.

2001 Merged with Texaco Inc. and changed name to ChevronTexaco Corporation. Became the second-largest U.S.-based energy company.

2002 Relocated corporate headquarters from San Francisco, California, to San Ramon, California.

2005 Acquired Unocal Corporation, an independent crude oil and natural gas exploration and production company. Unocal's upstream assets bolstered Chevron's already-strong position in the Asia-Pacific, U.S. Gulf of Mexico and Caspian regions. Changed name to Chevron Corporation to convey a clearer, stronger and more unified presence in the global marketplace.

STOCKHOLDER AND INVESTOR INFORMATION

Stock Exchange Listing
Chevron common stock is listed on the New York Stock Exchange. The symbol is "CVX."

Stockholder Information
Questions about stock ownership, changes of address, dividend payments or direct deposit of dividends should be directed to Chevron's transfer agent and registrar:
Mellon Investor Services LLC
480 Washington Boulevard
27th Floor
Jersey City, NJ 07130-2098
800 368 8357
www.melloninvestor.com

The Mellon Investor Services Program (800 842 7629, same address as above) features dividend reinvestment, optional cash investments of $50 to $100,000 a year, automatic stock purchase and safekeeping of stock certificates.

Dividend Payment Dates
Quarterly dividends on common stock are paid, following declaration by the Board of Directors, on or about the 10th day of March, June, September and December. Direct deposit of dividends is available to stockholders. For information, contact Mellon Investor Services. (See *Stockholder Information.*)

Annual Meeting
The Annual Meeting of stockholders will be held at 8:00 a.m., Wednesday, April 25, 2007, at:
Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324

Meeting notice and proxy materials are mailed in advance to stockholders, who are urged to review the materials and to vote their shares. Generally, stockholders may vote by telephone, on the Internet, by mail or by attending the meeting.

Electronic Access
Rather than receiving mailed copies, stockholders of record may sign up on our Web site, *www.icsdelivery.com/cvx/index.html*, for electronic access to future *Annual Reports* and proxy materials. Enrollment is revocable until each year's Annual Meeting record date. Beneficial stockholders may be able to request electronic access by contacting their broker or bank, or ADP at: *www.icsdelivery.com/cvx/index.html*.

Investor Information
Securities analysts, portfolio managers and representatives of financial institutions may contact:
Investor Relations
Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
925 842 5690
Email: *invest@chevron.com*

Publications and Other News Sources
The *Annual Report*, published in March, summarizes the company's financial performance in the preceding year and provides an outlook for the future.

The *Form 10-K*, prepared annually for the Securities and Exchange Commission, is available after March 1. The *Supplement to the Annual Report*, containing additional financial and operating data, is available after April 15. Both are available on the company's Web site, *www.chevron.com*, or copies may be requested by writing to:
Comptroller's Department
Chevron Corporation
6001 Bollinger Canyon Road, A3201
San Ramon, CA 94583-2324

The *Corporate Responsibility Report* is available in late April on the company's Web site, *www.chevron.com*, or a copy may be requested by writing to:
Policy, Government and
Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road, A2181
San Ramon, CA 94583-2324

Details of the company's *political contributions* for 2006 are available on the company's Web site, *www.chevron.com*, or by writing to:
Policy, Government and
Public Affairs
Chevron Corporation
6001 Bollinger Canyon Road, A2108
San Ramon, CA 94583-2324

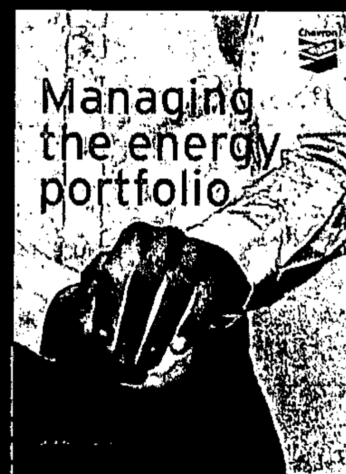
Information about *charitable and educational contributions* is available in the second half of the year on Chevron's Web site, *www.chevron.com*.

For additional information about the company and the energy industry, visit Chevron's Web site, *www.chevron.com*. It includes articles, news releases, speeches, quarterly earnings information, the *Proxy Statement* and the complete text of this *Annual Report*.

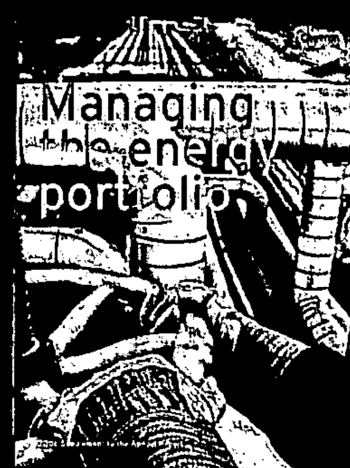
Legal Notice

As used in this report, the term "Chevron" and such terms as "the company," "the corporation," "our," "we" and "us" may refer to one or more of its consolidated subsidiaries or to all of them taken as a whole. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

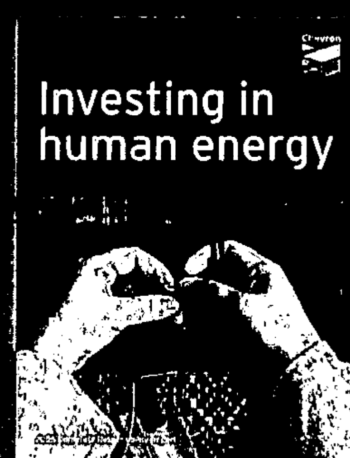
Corporate Headquarters
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
925 842 1000



2006 Annual Report



2006 Supplement to the Annual Report



2006 Corporate Responsibility Report

INDIVIDUALS NOT IDENTIFIED IN TEXT **Page 7:** Saudi Arabian Chevron's Nayef Al-Harbi, a desalter coordinator at Joint Operations, Wafra Field, Partitioned Neutral Zone; **Page 9:** Amoseas Indonesia Production Engineers Fachrul Subarkah (left) and Fernando Pasaribu, Darajat, Indonesia; **Page 12:** Senior Analyst Budi Riyanto, Maintenance Mechanical, North Duri Cogeneration Plant, Indonesia; **Page 14:** (top to bottom) Hathaiporn Samorn, Thailand, and Reginald Onyirioha and Olusola Bakare, Nigeria – Chevron employee participants, CoRE program, Colorado School of Mines, Golden, Colorado, United States.

PHOTOGRAPHY **Front/Back Cover:** Fredrik Broden; **Inside Front Cover/Page 1:** Francesco Lagnese, Riser, Getty Images; **Page 6:** Greg Smith; **Page 7:** Chris Martin; **Page 8:** Eric Myer; **Pages 9, 21 (left):** Peter Cannon; **Pages 10, 14:** Paul S. Howell; **Page 11:** Mark Viker, Stone, Getty Images; **Page 12:** Melbourne the Photographer; **Page 13:** D. Ross Cameron, The Oakland Tribune; **Page 15:** Claire Maneja; **Pages 16, 20:** Jim Karageorge; **Page 19:** José Pinto; **Page 21:** (right) Christian Sprogoe; **Page 22:** (left) Jamie Koh, Joe Lynch; **Page 23:** (left) Marilyn Hulbert, Michael Goldwater; **Inside Back Cover:** (top to bottom) Fredrik Broden, Marilyn Hulbert, Pradonggo.

PORTRAITS **Page 2:** Eric Myer; **Pages 6, 8, 11, 13:** Jim Karageorge; **Page 15:** Victor Turco.

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PRINTING Graphic Press, Los Angeles

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Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
www.chevron.com

912-0927

Appendix X

Financial Assurance Documents

Chevron

Oronite

Mike Burnside
Americas Regional
Manager

Oak Point Plant
Chevron Oronite Co. LLC
P. O. Box 70
10285 Highway 23
Belle Chasse, LA 70037
Tel 504-391-6101
Fax 504-391-6356

April 25, 2007

Louisiana Department of Environmental Quality
Post Office Box 4313
Baton Rouge, Louisiana 70821-4313
Attention: Office of Environmental Services,
Water and Waste Permits Division

Subject: Letter of Credit Transmittal
Chevron Oronite Company, LLC
Agency Interest No. 1708
PER 20050009

Dear Sir:

Chevron Oronite Company, LLC, is providing the Louisiana Department of Environmental Quality with a Letter of Credit as the financial assurance mechanism for operation of the Type I facility identified above. The following information is provided as required by LAC33:727.A.1.d.ii.c:

Letter of Credit No.: **839BCG0700166**

Issuing Institution: **Deutsche AG New York**

Date of Issue: **April 3, 2007**

Solid Waste ID No: **P-0112-A-1**

Site Name: **Chevron Oronite Company, LLC**

Facility Name: **Oak Point Plant**

Facility Permit No.: **P-0112-A-1 / GD-075-1551**

Amount of Funds Assured for Liability Coverage by Letter of Credit: **$1 million**

If there are questions concerning the reported information, please contact Troy M. Sampey of my staff at (504) 391-6314 or email tsampey@chevron.com.

Sincerely,

MHBurnside

Mike Burnside

Deutsche Bank

Deutsche Bank AG New York
Trade and Risk Services
60 Wall Street / NYC60-2517
New York, NY 10005-2858

SOLID WASTE FACILITY
IRREVOCABLE LETTER OF CREDIT

Date: April 3, 2007

Secretary
Louisiana Department of Environmental Quality
Post Office Box 4313
Baton Rouge, Louisiana 70821-4313
Attention: Office of Environmental Services,
Water and Waste Permits Division

Dear Sir:

We hereby establish our Irrevocable Standby Letter of Credit No. 839BGC0700166 at the request and for the account of Chevron Oronite Company LLC, 21285 Highway 23 South, Belle Chase 70037 for its Site ID No: 1708, Oak Point Plant, and facility permit number: GD-075-1511 / P-0112-A-1 at Belle Chase, Louisiana, in favor of any governmental body, person, or other entity for any sum or sums up to the aggregate amount of US$1,000,000.00 (One Million United States Dollars) upon presentation of:

1. A final judgment issued by a competent court of law in favor of a governmental body, person, or other entity and against Chevron Oronite Company LLC for sudden and accidental occurrences for claims arising out of injury to persons or property due to the operation of the solid waste site at the Chevron Oronite Company LLC at Site ID No: 1708, Belle Chase, LA as set forth in the LAC 33:VII.727.A.1.

2. A sight draft bearing reference to the Letter of Credit No. 839BGC0700166 drawn by the governmental body, person, or other entity, in whose favor the judgment has been rendered as evidenced by documentary requirement in Paragraph 1.

The Letter of Credit is effective as of April 3, 2007 and will expire on April 4, 2008, but such expiration date will be automatically extended for a period of at least one year on the above expiration date and on each successive expiration date thereafter, unless, at least 120 days before the then-current expiration date, we notify both the Administrative Authority and Chevron Oronite Company LLC by certified mail that we have decided not to extend this Letter of Credit beyond the then-current expiration date. In the event we give such notification, any unused portion of this Letter of Credit shall be available upon presentation of your sight draft for 120 days after the date of receipt by both the Department of Environmental Quality and Chevron Oronite Company LLC as shown on the signed return receipts.

Irrevocable Standby Letter of Credit No. 839BGC0700166

Whenever this Letter of Credit is drawn under and in compliance with the terms of this credit, we shall duly honor such draft upon presentation to us, and we shall deposit the amount of the draft directly into the standby trust fund of Chevron Oronite Company LLC in accordance with the administrative authority's instructions.

Except to the extent otherwise expressly agreed to, the Uniform Customs and Practice for Documentary Letters of Credit (1993), International Chamber of Commerce Publication No. 500, shall apply to this Letter of Credit.

We certify that the wording of this Letter of Credit is identical to the wording specified in LAC 33:VII.727.A.1.d.ii.(e), effective on the date shown above.

Very truly yours,

DEUTSCHE BANK AG,
NEW YORK BRANCH

Lynn Nicaretta	Ann Thompson
Vice President	Asst. Vice President

SOLID WASTE FACILITY
TRUST AGREEMENT/STANDBY TRUST AGREEMENT

Trust Agreement, the "Agreement" entered into as of July 6, 2007 by and between Chevron Oronite Company LLC, a Delaware Limited Liability Company, the "Grantor," and Deutsche Bank Trust Company Americas, a New York banking corporation, the "Trustee."

WHEREAS, the Department of Environmental Quality of the State of Louisiana, an agency of the State of Louisiana, has established certain regulations applicable to the Grantor, requiring that a permit holder or applicant for a permit of a solid waste processing or disposal facility shall provide assurance that funds will be available when needed for payment of any sums due under one or more final judgments issued, in each case, by a competent court of law in favor of an agency of the State of Louisiana, a person or other entity against the permit holder for sudden and accidental occurrences for claims ("Liability Claims") arising out of injury to persons or property due the operation of the of such facility;

WHEREAS, the Grantor has elected to establish a trust to provide all or part of such financial assurance for Liability Claims arising with respect to the facility identified in Schedule A hereto (the "Facility");

WHEREAS, the Grantor, acting through its duly authorized officers, has selected Deutsche Bank Trust Company Americas to be the trustee under this Agreement, and Deutsche Bank Trust Company Americas is willing to act as trustee.

NOW, THEREFORE, the Grantor and the Trustee agree as follows:

SECTION 1. DEFINITIONS

As used in this Agreement:

(a). The term *Grantor* means the permit holder or applicant who enters into this Agreement and any successors or assigns of the Grantor.

(b). The term *Trustee* means the Trustee who enters into this Agreement and any successor trustee.

(c). The term *Secretary* means the Secretary of the Louisiana Department of Environmental Quality.

(d). The term *administrative authority* means the Secretary or a person designated by him to act therefore.

SECTION 2. IDENTIFICATION OF FACILITIES AND COST ESTIMATES

This Agreement pertains to the facilities and cost estimates identified on attached Schedule A.

SECTION 3. ESTABLISHMENT OF FUND

The Grantor and the Trustee hereby establish a trust fund, the "Fund", for the benefit of the Louisiana Department of Environmental Quality. The Grantor and the Trustee intend that no third party shall have access to the Fund except as herein provided. The Fund is established initially as consisting of the property, which is acceptable to the Trustee, described in Schedule B attached hereto. Such property and any other property subsequently transferred to the Trustee is referred to as the Fund, together with all earnings and profits thereon, less any payments or distributions made by the Trustee pursuant to this Agreement. The Fund shall be held by the Trustee, in trust, as hereinafter provided. The Trustee shall not be responsible nor shall it undertake any responsibility for the amount or adequacy of, nor any duty to collect from the Grantor, any payments necessary to discharge any liabilities of the Grantor established by the administrative authority.

SECTION 4. PAYMENT FOR LIABILITY CLAIMS COVERAGE

The Trustee shall make payments from the Fund as the administrative authority shall direct, in writing, to provide for the payment of the Liability Claims with respect to the Facility. The Trustee shall reimburse the Grantor or other persons as specified by the administrative authority from the Fund for Liability Claims in such amounts as the administrative authority shall direct in writing. In addition, the Trustee shall refund to the Grantor such amounts as the administrative authority specifies in writing. Upon refund, such funds shall no longer constitute part of the Fund as defined herein.

SECTION 5. PAYMENTS COMPRISED BY THE FUND

Payments made to the Trustee for the Fund shall consist of cash or securities acceptable to the Trustee.

SECTION 6. TRUSTEE MANAGEMENT

The Trustee shall invest and reinvest the principal and income of the Fund and keep the Fund invested as a single fund, without distinction between principal and income, in accordance with general investment policies and guidelines which the Grantor may communicate in writing to the Trustee from time to time, subject, however, to the provisions of this Section. In investing, reinvesting, exchanging, selling, and managing the Fund, the Trustee shall discharge his duties with respect to the trust fund solely in the interest of the beneficiary and with the care, skill, prudence, and diligence under the circumstances then prevailing which persons of prudence, acting in a like capacity and familiar with such matters, would use in the conduct of an enterprise of like character and with like aims, except that:

(a). Securities or other obligations of the Grantor, or any owner of the Facility or any of their affiliates as defined in the Investment Company Act of 1940, as amended, 15 U.S.C. 80a-2.(a), shall not be acquired or held, unless they are securities or other obligations of the federal or a state government.

(b). The Trustee is authorized to invest the Fund in time or demand deposits of the Trustee, to the extent insured by an agency of the federal or state government; and

(c). The Trustee is authorized to hold cash awaiting investment or distribution uninvested for a reasonable time and without liability for the payment of interest thereon.

SECTION 7. COMMINGLING AND INVESTMENT

The Trustee is expressly authorized, at its discretion:

(a). To transfer from time to time any or all of the assets of the Fund to any common, commingled, or collective trust fund created by the Trustee in which the Fund is eligible to participate, subject to all provisions thereof, to be commingled with the assets of other trusts participating therein; and

(b). To purchase shares in any investment company registered under the Investment Company Act of 1940, 15 U.S.C. 80a-1, et seq., including one which may be created, managed, or underwritten, or one to which investment advice is rendered or the shares of which are sold by the Trustee. The Trustee may vote such shares at its discretion.

SECTION 8. EXPRESS POWERS OF TRUSTEE

Without in any way limiting the powers and discretion conferred upon the Trustee by the other provisions of this Agreement or by law, the Trustee is expressly authorized and empowered:

(a). To sell, exchange, convey, transfer, or otherwise dispose of any property held by it, by public or private sale. No person dealing with the Trustee shall be bound to see to the application of the purchase money or to inquire into the validity or expediency of any such sale or other disposition;

(b). To make, execute, acknowledge, and deliver any and all documents of transfer and conveyance and any and all other instruments that may be necessary or appropriate to carry out the powers herein granted;

(c). To register any securities held in the Fund in its own name or in the name of a nominee and to hold any security in bearer form or in book entry, or to combine certificates representing such securities with certificates of the same issue held by the Trustee in other fiduciary capacities, or to deposit or arrange for the deposit of such securities in a qualified central depository even though, when so deposited, such securities may be merged and held in bulk in the name of the nominee of such depository with other securities deposited therein by another person, or to deposit or arrange for the deposit of any securities issued by the United States Government, or any agency or instrumentality thereof, with a Federal Reserve Bank, but the books and records of the Trustee shall at all times show that all securities are part of the Fund;

(d). To deposit any cash in the Fund in interest-bearing accounts maintained or savings certificates issued by the Trustee, in its separate corporate capacity, or in any other banking institution affiliated with the Trustee, to the extent insured by an agency of the federal or state government; and

(e). To compromise or otherwise adjust all claims in favor of, or against, the Fund.

SECTION 9. TAXES AND EXPENSES

All taxes of any kind that may be assessed or levied against or in respect of the Fund and all brokerage commissions incurred by the Fund shall be paid from the Fund. All other expenses incurred by the Trustee in connection with the administration of this Trust, including fees for legal services rendered to the Trustee, the compensation of the Trustee to the extent not paid directly by the Grantor, and other proper charges and disbursements of the Trustee, but excluding expenses, charges and disbursements incurred in connection with the day-to-day administration services for the Trust Fund, including receipt and safe keeping of property, collection of income, disbursements, reporting and any other duties required by the Trustee under the terms of this Agreement, shall be paid from the Fund. The Trustee shall notify the Grantor before incurring fees for legal services or other consultants or experts that exceed more than $5,000.

SECTION 10. ANNUAL VALUATION

The Trustee shall annually, at least 30 days prior to the anniversary date of establishment of the Fund, furnish to the Grantor and to the administrative authority a statement confirming the value of the Trust. Any securities in the Fund shall be valued at market value as of no more than 60 days prior to the anniversary date of establishment of the Fund. The failure of the Grantor to object in writing to the Trustee, within 90 days after the statement has been furnished to the Grantor and the administrative authority, shall constitute a conclusively binding assent by the Grantor, barring the Grantor from asserting any claim or liability against the Trustee with respect to matters disclosed in the statement.

SECTION 11. ADVICE OF COUNSEL

The Trustee may from time to time consult with counsel, who may be counsel to the Grantor, with respect to any questions arising as to the construction of this Agreement or any action to be taken hereunder. The Trustee shall be fully protected, to the extent permitted by law, in acting upon the advice of counsel.

SECTION 12. TRUSTEE COMPENSATION

The Trustee shall be entitled to reasonable compensation for its services as agreed upon in writing from time to time with the Grantor.

SECTION 13. SUCCESSOR TRUSTEE

The Trustee may resign or the Grantor may replace the Trustee, but such resignation or replacement shall not be effective until the Grantor has appointed a successor or trustee and this successor accepts the appointment. The successor trustee shall have the same powers and duties as those conferred upon the Trustee hereunder. Upon the successor trustee's acceptance of the appointment, the Trustee shall assign, transfer, and pay over to the successor trustee the funds and properties then constituting the Fund. If for any reason the Grantor cannot or does not act in the event of the resignation of the Trustee, the Trustee may apply to a court of competent jurisdiction for the appointment of a successor trustee or for instructions. The successor trustee shall in writing specify to the Grantor, the administrative authority, and the present Trustee by certified mail 10 days before such change becomes effective the date on which it assumes administration of the trust. Any expenses incurred by the Trustee as a result of any of the acts contemplated by this Section shall be paid as provided in Section 9.

SECTION 14. INSTRUCTIONS TO THE TRUSTEE

All orders, requests, and instructions by the Grantor to the Trustee shall be in writing, signed by the persons designated in the attached Exhibit A or such other persons as the Grantor may designate by amendment to Exhibit A. The Trustee shall be fully protected in acting without inquiry in accordance with the Grantor's orders, requests, and instructions. All orders, requests, and instructions by the administrative authority to the Trustee shall be in writing and signed by the administrative authority. The Trustee shall act and shall be fully protected in acting in accordance with such orders, requests, and instructions. The Trustee shall have the right to assume, in the absence of written notice to the contrary, that no event constituting a change or termination of the authority of any person to act on behalf of the Grantor or administrative authority hereunder has occurred. The Trustee shall have no duty to act in the absence of such orders, requests, and instructions from the Grantor and/or administrative authority, except as provided for herein.

SECTION 15. NOTICE OF NONPAYMENT

The Trustee shall notify the Grantor and the administrative authority, by certified mail, within 10 days following the expiration of the 30-day period after the anniversary of the establishment of the Trust, if no payment is received from the Grantor during that period. After the pay-in period is completed, the Trustee shall not be required to send a notice of nonpayment.

SECTION 16. AMENDMENT OF AGREEMENT

This Agreement may be amended by an instrument in writing executed by the Grantor, the Trustee, and the administrative authority, or by the Trustee and the administrative authority, if the Grantor ceases to exist.

SECTION 17. IRREVOCABILITY AND TERMINATION

Subject to the right of the parties to amend this Agreement as provided in Section 16, this Trust shall be irrevocable and shall continue until terminated at the written agreement of the Grantor, the Trustee, and the administrative authority, or by the Trustee and the administrative authority, if the Grantor ceases to exist. Upon termination of the Trust, all remaining trust property, less final trust administration expenses, shall be delivered to the Grantor.

SECTION 18. IMMUNITY AND INDEMNIFICATION

The Trustee shall not incur personal liability of any nature in connection with any act or omission, made in good faith, in the administration of this Trust, or in carrying out any direction by the Grantor or the administrative authority issued in accordance with this Agreement. The Trustee shall be indemnified and saved harmless by the Grantor or from the Trust Fund, or both, from and against any personal liability to which the Trustee may be subjected by reason of any act or conduct in its official capacity, including all reasonable expenses incurred in its defense in the event that the Grantor fails to provide such defense, except where such personal liability is due to the negligence, gross negligence or willful misconduct of the Trustee.

SECTION 19. CHOICE OF LAW

This Agreement shall be administered, construed, and enforced according to the laws of the State of Louisiana.

SECTION 20. INTERPRETATION

As used in this Agreement, words in the singular include the plural and words in the plural include the singular. The descriptive headings for each Section of this Agreement shall not affect the interpretation or the legal efficacy of this Agreement.

(The next page is the signature page.)

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed by their respective officers duly authorized and their corporate seals to be hereunto affixed and attested to as of the date first above written. The parties below certify that the wording of this Agreement is identical to the wording specified in LAC 33:VII.727.A.2.d.ix, on the date first written above.

WITNESSES:

[Signature] Sky Huber
[Name] Sky Huber
[Its] Financial Analyst

[Signature] Grace Perez
[Name] Grace Perez
[Its] Financial Analyst

[Seal]

GRANTOR:

H.B. Sheppard
H. B. Sheppard
Assistant Treasurer

R. C. Gordan
Assistant Treasurer

TRUSTEE:

By:
Name: RICHARD L. BUCKWALTER
Its: DIRECTOR

By: Wanda Camacho
Name: Wanda Camacho
Its: Vice President

CALIFORNIA ALL-PURPOSE ACKNOWLEDGMENT

State of California

County of Contra Costa

On 7/6/07 before me, Andrew Tomerson, Notary Public.
Date / Name and Title of Officer (e.g., "Jane Doe, Notary Public")

personally appeared R. C. Gordan & H. B. Sheppard
Name(s) of Signer(s)

☒ personally known to me

☐ (or proved to me on the basis of satisfactory evidence)

to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

ANDREW A. TOMERSON
Commission # 1632640
Notary Public - California
Contra Costa County
MyComm. Expires Jan 20, 2010

WITNESS my hand and official seal.

Place Notary Seal Above

Signature of Notary Public

OPTIONAL

Though the information below is not required by law, it may prove valuable to persons relying on the document and could prevent fraudulent removal and reattachment of this form to another document.

Description of Attached Document

Title or Type of Document: Solid Waste Facility, Trust Agreement / Standby Trust Agreem

Document Date: 7/6/07 Number of Pages: 6

Signer(s) Other Than Named Above: N/A

Capacity(ies) Claimed by Signer(s)

Signer's Name: R. C. Gordan.
☐ Individual
☒ Corporate Officer — Title(s): Assistant Treasurer
☐ Partner — ☐ Limited ☐ General
☐ Attorney in Fact
☐ Trustee
☐ Guardian or Conservator
☐ Other: ____

RIGHT THUMBPRINT OF SIGNER
Top of thumb here

Signer Is Representing: Chevron Oronite Company LLC

Signer's Name: H. B. Sheppard
☐ Individual
☒ Corporate Officer — Title(s): Assistant Treasurer
☐ Partner — ☐ Limited ☐ General
☐ Attorney in Fact
☐ Trustee
☐ Guardian or Conservator
☐ Other: ____

RIGHT THUMBPRINT OF SIGNER
Top of thumb here

Signer Is Representing: Chevron Oronite Company LLC

SCHEDULE A

Facilities and liability coverage pertaining to this Agreement for which financial assurance is demonstrated by this Agreement:

Site Identification Number:	1708
Site Name:	Chevron Oronite Company, LLC
Facility Name:	Oak Point Plant
Address:	10285 Highway 23 South Belle Chase, LA 70037
Facility Permit Number:	GD-075-1511 / P-0112-A-1
Aggregate Amount of Liability Coverage:	USD $1,000,000.00

SCHEDULE B

The Agreement is not presently funded but shall be funded by the Deutsche Bank Irrevocable Standby Letter of Credit No. 839BGC0700166 used by the Grantor in accordance with the terms of that document.

Chevron

Lisa M. Lemanczyk
Senior Counsel

Chevron U.S.A., Inc.
Law Department
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
Tel (925) 842-5037
Fax (925) 842-2011
lisalemanczyk@chevron.com

March 26, 2007

Dr. Mike McDaniel, Secretary
Louisiana Department of Environmental Quality
602 N. 5th Street
Baton Rouge, LA 70802

Solid Waste Sites - Louisiana
Financial Assurance for Closure and Post-Closure Care and Liability Coverage

Dear Dr. McDaniel:

Attached, as required by Louisiana Solid Waste Regulations, are the following Chevron Corporation items to be filed on behalf of our subsidiary, Chevron U.S.A. Inc.:

1. Chief Financial Officer letter dated March 31, 2006.
2. Corporate Guarantee for liability coverage, closure and post-closure care.
3. 2005 Chevron Form 10-K containing our Report of Independent Registered Public Accounting Firm.
4. Accountant's Special Report.
5. Bond Rating Information

The enclosed documents cover our solid waste facility Storm Water Treatment System Permit # P-0112:

Chevron U.S.A. Inc.
Highway 23, P. O. Box 70
Belle Chasse, LA 70037

This facility is currently in use and will remain so for the indefinite future.

The closure and post-closure costs have been increased by 2.9%, which is the estimated inflation factor as of February, 2007.

If you have any questions, please call me at the above phone number.

Sincerely,

Lisa M. Lemanczyk

Lisa M. Lemanczyk

Attachments (5)

Solid Waste Sites - Louisiana
Financial Assurance for Closure
And Post-Closure Care
And Liability Coverage
March 26, 2007

bcc: T. Sampey
B. Kim, PricewaterhouseCoopers, LLP

Chevron

Stephen J. Crowe
Vice President and
Chief Financial Officer

Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
Tel (925) 842-3232
Fax (925) 842-6047

March 26, 2007

Dr. Mike McDaniel, Secretary
Attn: Office of Environmental Services,
Water and Waste Permits Division
Louisiana Department of Environmental Quality
Post Office Box 4313
Baton Rouge, Louisiana 70821-4313

Dear Dr. McDaniel:

I am the Chief Financial Officer of Chevron Corporation, 6001 Bollinger Canyon Road, San Ramon, California. This letter is in support of this firm's use of the financial test to demonstrate financial responsibility for liability coverage, closure and post-closure, as specified in LAC 33:VII.727.A.1 and A.2.

1. The firm identified above is the parent corporation of the permit holder applicant for a standard permit of the following solid waste facilities, whether in Louisiana or not, for which liability coverage is being demonstrated through the financial test specified in LAC 33: VII.727.A.1. The amount of annual aggregate liability coverage covered by the test is shown for each facility:

LAD 034199802 Chevron U.S.A. Inc (Hazardous Waste) P.O. Box 70 Belle Chasse, LA 70037	Annual Aggregate Liability: $2,000,000
CAD 043237486 Chevron U.S.A. Inc. 940 Hensley Street Richmond, CA 94804	Annual Aggregate Liability: $8,000,000
Kansas Solid Waste Permit No. 796 Chevron U.S.A. Inc. Jayhawk C&D Landfill Alternate Highway 69 Galena, KS 66739	Annual Aggregate Liability: $1,000,000

OHD00502410 Chevron U.S.A. Inc. Toledo Refinery 2395 Front Street Toledo, OH 43605	Annual Aggregate Liability:	$8,000,000
OHD004254132 Chevron U.S.A. Inc. Cincinnati Refinery P.O. Box 96 North Bend, OH 45052	Annual Aggregate Liability:	$8,000,000
MSD 054179403 Chevron U.S.A. Inc. Pascagoula Refinery P.O. Box 1300 Pascagoula, MS 39567	Annual Aggregate Liability:	$8,000,000
UTD 092029768 Chevron U.S.A. Inc. Salt Lake Refinery P.O. Box 25117 Salt Lake City, UT 84125	Annual Aggregate Liability:	$8,000,000
NJD 081982902986 Chevron U.S.A. Inc. Perth Amboy Refinery 1200 State Street Perth Amboy, NJ 08861	Annual Aggregate Liability:	$8,000,000
WYD 088677943 Chevron Environmental Services Co. Casper Plant P.O. Box 307 Evansville, WY 82636	Annual Aggregate Liability:	$10,000,000
CAD 008336901 Chevron U.S.A. Inc. El Segundo Refinery P.O. Box 97 El Segundo, CA 90245	Annual Aggregate Liability:	$8,000,000

CAD009114919 Chevron U.S.A. Inc. Richmond Refinery P.O. Box 1272 Richmond, CA 94802	Annual Aggregate Liability: $8,000,000
EPA I.D. No. CAD 041652090 PureGro Co. Corcoran Facility 6991 Nevada Ave. Corcoran, CA 93212	Annual Aggregate Liability: $8,000,000
CAT 080010283 Chevron U.S.A. Inc. Westside Disposal Facility (aka EPC Westside) 26244 Highway 33 Fellows, CA 93324	Annual Aggregate Liability: $8,000,000
EPA I.D. No. TXD010794097 Union Oil Company of California Beaumont Terminal 237 Beaumont Beaumont, TX 77627	Annual Aggregate Liability: $8,000,000

2. The firm identified above is the parent corporation of the permit holder or applicant for a standard permit of the following solid waste facilities, whether in Louisiana or not, for which financial assurance for closure and post-closure is demonstrated through a financial test similar to that specified in LAC 33:VII.727.A.2 or other forms of self insurance. The current closure and post-closure cost estimates covered by the test are shown for each facility:

Site ID No. GD-075-1511/ Permit # P-0112

Chevron U.S.A. Inc.	Closure Cost	$2,461,193
Oak Point Plant	Post-Closure	0
Highway 23 – P.O. Box 70	(clean closure)	
Belle Chasse, LA 70037		

TXD 007378995		
Chevron Environmental Services Company	Post-Closure Cost	$368,398
Amarillo Plant	Corrective Action	$3,965,873
315 S. Grand		
Amarillo, TX 79104		
	Closure Cost	
HW 50159-000	CAMU	$9,773,946
Chevron U.S.A. Inc.	Post-Closure Cost	$1,447,500
El Paso Refinery	Agreed Order	
P.O. Box 20002	#2002-0272-IHW	
El Paso, TX 79998		
Chevron Environmental Management Company	Post-Closure Cost	$830,350
El Paso Refinery	(SWR No. 36419)	
P.O. Box 20002		
El Paso, TX 79998		
EPA I.D. No. TXD010794097		
Union Oil Company of California		
Beaumont Terminal	Post-Closure Cost	$341,844
237 Beaumont	Corrective Action	$2,036,998
Beaumont, TX 77627		
WYD 088677943		
Chevron Environmental Services Company	Closure Cost	0
Casper Plant	Corrective Action	$3,481,753
P.O. Box 307	Post-Closure Cost	$7,810,628
Evansville, WY 82636		
Chevron U.S.A. Inc.	Closure Cost	$2,656,981
El Segundo Refinery	Post-Closure Cost	$16,387,554
P.O. Box 97		
El Segundo, CA 90245		
HIT 160010005		
Chevron U.S.A. Inc.	Closure	0
Hawaii Refinery	Post-Closure	$69,461
P.O. Box 29789		
Honolulu, HI 96820		

Solid Waste Permit No. 796

Chevron U.S.A. Inc.	Closure Cost	
Jayhawk C&D Landfill	Post-Closure Cost	$1[illegible]
Alternate Highway 69		
Galena, KS 66739		
Chevron Environmental Services Company	Closure Cost	[illegible]
Lockport Plant	Corrective Action	$9,3[illegible]
W 2nd Street	Post-Closure Cost	$6[illegible]
Lockport, IL 60441		
Chevron U.S.A. Inc.	Closure Cost	$12,4[illegible]
Texaco Research Center–Beacon	Post-Closure Cost	$7[illegible]
Texaco Fuels and Lubricants Center		
Old Glenham Road		
Glenham, NY 12527		
MSD 054179403		
Chevron U.S.A. Inc.	Closure Cost	$2,0[illegible]
Pascagoula Refinery	Post-Closure Cost	$1,0[illegible]
P.O. Box 1300		
Pascagoula, MS 39567		
NJD 081982902		
Chevron U.S.A. Inc.	Closure Cost	$2,0[illegible]
Perth Amboy Refinery	Post-Closure Cost	$2,9[illegible]
1200 State Street		
Perth Amboy, NJ 08861		
CAD 009114919		
Chevron U.S.A. Inc.	Closure Cost	$1,[illegible]
Richmond Refinery	Post-Closure Cost	$30,[illegible]
P.O. Box 1272		
Richmond, CA 94802		
Toledo Refinery	Closure Cost	[illegible]
2395 Front Street	Post-closure Cost	$[illegible]
Toledo, OH 43605		

OHD 004254132 Chevron U.S.A. Inc. Cincinnati Refinery P.O. Box 96 North Bend, OH 45052	Post-Closure Cost	$230,598
CAD 043237486 Chevron U.S.A. Inc. 940 Hensley Street Richmond, CA 94804	Closure Cost Post-Closure Cost	$78,506,173 $17,471,704
Docket #HSA97/98--005 Calspray Site 135 Walker Street Watsonville, CA 95076	Work	$546,801
CAD 980636781 Chevron Environmental Services Company Pacific Coast Pipeline Site 67 East Telegraph Road Fillmore, CA 93016	Closure Cost Post-Closure Cost	$5,934,869 $1,194,669
CAT 080010283 Chevron U.S.A. Inc. Westside Disposal Facility (aka EPC Westside) 26244 Highway 33 Fellows, CA 93324	Post-Closure Cost	$1,005,290
Docket# CERCLA-08-2003-0014 Chevron U.S.A. Inc. Northwest Oil Drain Salt Lake County, UT	Work	$820,000
UTD 092029768 Chevron U.S.A. Inc. Salt Lake Refinery P.O. Box 25117 Salt Lake City, UT 84125	Post-Closure Cost Corrective Action	$2,160,000 $1,275,000

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3. This firm guarantees through a corporate guarantee similar to that specified in LAC 33:VII.727.A.1 and 2, liability coverage, closure and post-closure care of the following solid waste facilities, whether in Louisiana or not, of Chevron U.S.A. Inc., which is a subsidiary of this firm. The amount of annual aggregate liability coverage covered by the guarantee for each facility and the current cost estimates for the closure and post-closure care so guaranteed is shown for each facility:

Chevron U.S.A. Inc.		
Highway 23, P.O. Box 70	Closure Cost	$2,461,193
Belle Chasse, LA 70037	Post-Closure Cost	0
Site ID#: GD-075-1511		
Site Name: Oak Point Plant		
Storm Water Treatment System		
Facility Permit No.: P-0112		
LAD 034199802		
Chevron U.S.A. Inc	Closure Cost	0
P.O. Box 70	Post-Closure Cost	$3,724,406
Belle Chasse, LA 70037	Liability	$2,000,000
CAD 043237486		
Chevron U.S.A. Inc.	Closure Cost	$78,506,173
940 Hensley Street	Post-Closure Cost	$17,471,704
Richmond, CA 94804	Liability	$8,000,000
Kansas Solid Waste Permit No. 796		
Chevron U.S.A. Inc.	Closure Cost	0
Jayhawk C&D Landfill	Post-Closure Cost	$165,000
Alternate Highway 69	Liability	$1,000,000
Galena, KS 66739		
OHD00502410		
Chevron U.S.A. Inc.	Closure Cost	0
Toledo Refinery	Post-Closure Cost	$487,000
2395 Front Street	Liability	$8,000,000
Toledo, OH 43605		
OHD004254132		
Chevron U.S.A. Inc.	Closure Cost	0
Cincinnati Refinery	Post-Closure Cost	$230,598
P.O. Box 96	Liability	$8,000,000
North Bend, OH 45052		

VII-JK (CERCLA Remediation Action)	Unit 1	$37,700,559
Chevron Environmental Services Co.	Unit 2	$13,183,634
Chemplex Site	Liability	0
4010 21st Street		
Camanche, IA 52730		
MSD054179403		
Chevron U.S.A. Inc.	Closure Cost	$2,029,188
Pascagoula Refinery	Post-Closure Cost	$1,083,537
P.O. Box 1300	Liability	$8,000,000
Pascagoula, MS 39567		
UTD 092029768		
Chevron U.S.A. Inc.	Corrective Action	$1,275,000
Salt Lake Refinery	Post-Closure Cost	$2,160,000
P.O. Box 25117	Liability	$8,000,000
Salt Lake City, UT 84125		
NJD 081982902986		
Chevron U.S.A. Inc.	Closure Cost	$2,041,600
Perth Amboy Refinery	Post-Closure Cost	$2,990,000
1200 State Street	Liability	$8,000,000
Perth Amboy, NJ 08861		
WYD 088677943		
Chevron Environmental Services Company	Closure Cost	0
Casper Plant	Post-Closure Cost	$7,810,628
P.O. Box 307	Corrective Action	$3,481,753
Evansville, WY 82636	Liability	$10,000,000
CAD 008336901		
Chevron U.S.A. Inc.	Closure Cost	$2,656,981
El Segundo Refinery	Post-Closure Cost	$16,387,554
P.O. Box 97	Liability	$8,000,000
El Segundo, CA 90245		
Chevron Environmental Management Company		
Pacific Coast Pipeline Site	Closure Cost	$5,934,869
67 East Telegraph Road	Post-Closure Cost	$1,194,669
Fillmore, CA 93016	Liability	0

CAD009114919		
Chevron U.S.A. Inc.	**Closure Cost**	**$1,337,700**
Richmond Refinery	**Post-Closure Cost**	**$30,335,464**
P.O. Box 1272	**Liability**	**$8,000,000**
Richmond, CA 94802		
DTSC Calsites Database 44280006		
Chevron Environmental Management	Work	$546,801
Calspray Site	Liability	0
135 Walker Street		
Watsonville, CA 95076		
EPA I.D. No. CAD 041652090		
PureGro Co.	Closure Cost	0
Corcoran Facility	Post-Closure Cost	$818,750
6991 Nevada Ave.	Liability	$8,000,000
Corcoran, CA 93212		
CAT 080010283		
Chevron U.S.A. Inc.	Closure Cost	0
Westside Disposal Facility	Post-Closure Cost	$1,005,290
26244 Highway 33	Liability	$8,000,000
Fellows, CA 93324		
HIT 160010005	Closure Cost	0
Chevron U.S.A. Inc.	Post-Closure Cost	$69,461
Hawaii Refinery	Liability	0
P.O. Box 29789		
Honolulu, HI 96820		
ILD 041518861		
Chevron Environmental Service Co.	Closure Cost	0
Lockport Plant	Post-Closure Cost	$695,380
301 W. 2nd Street	Corrective Action	$9,365,133
Lockport, IL 60441	Liability	0
TXD 007378995	Closure Cost	$368,398
Chevron Environment Services Co.	Post-Closure Cost	0
Amarillo Plant	Corrective Action	$3,965,873
315 S. Grand	Liability	0
Amarillo, TX 79104		

HW 50159-000		
Chevron U.S.A. Inc.	Closure Cost CAMU	$9,773,946
El Paso Refinery	Post-Closure Cost	$1,447,500
P.O. Box 20002	Liability	0
El Paso, TX 79998		
EPA I.D. No. TXD010794097		
Union Oil Company of California	Closure Cost	0
Beaumont Terminal	Post-Closure Cost	$341,844
237 Beaumont	Corrective Action	$2,036,998
Beaumont, TX 77627	Liability	$8,000,000
Chevron Environmental Management Company	Post-Closure Cost (SWR No. 36419)	$830,350
El Paso Refinery	Liability	0
P.O. Box 2002		
El Paso, TX 79998		
Docket# CERCLA-08-2003-0014	Work	$820,000
Chevron U.S.A. Inc.	Liability	0
Northwest Oil Drain		
Salt Lake County, UT		
CSX Powell Duffryn Site	Corrective Action	$650,247
Savannah, Chatham County, GA	Corrective Action	$65,636
CSX Parcel	Liability	0
SEDA Parcel		
California Dept. of Toxic Substances		
Control v. Chevron U.S.A. Inc.	Work	$10,000,000
Purity Oil Sales, Inc.	Liability	0
Malaga, Fresno County, CA		
Chevron Environmental Management. Company		
Star Lake Canal	Work	$1,435,000
Jefferson County, TX	Liability	0

4. This firm is the owner or operator of the following solid waste facilities, whether in Louisiana or not, for which financial assurance for liability coverage, closure and/or post-closure care is not demonstrated either to the U.S. Environmental Protection Agency or to a state through a financial test or any other financial assurance mechanism similar to those specified in LAC 33: VII.727.A.1 and/or 2. The current closure and/or post-closure cost estimates not covered by such financial assurance are shown for each facility: None.

This firm is required to file a Form 10-K with the Securities and Exchange Commission (SEC) for the latest fiscal year.

The fiscal year of this firm ends on December 31. The figures for the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year, ended December 31, 2006.

ALTERNATIVE II

1.	Sum of current closure and post-closure cost estimates.	$ 350,004,952	
2.	Amount of annual aggregate liability coverage to be demonstrated.	$ 101,000,000	
3.	Sum of lines 1 and 2	$ 451,004,952	
4.	Current bond rating of most recent issuance and name of rating service.	AA Standard & Poors	
5.	Date of issuance of bond.	February 2003	
6.	Date of maturity of bond.	February 2008	
7.	Tangible net worth.	$ 63,970,338,000	
8.	Total assets in the U.S.	$ 45,258,000,000	

		Yes	No
9.	Is line 7 at least $10 million?	X	
10.	Is line 7 at least 6 times line 3?	X	
11.	Are at least 90% of assets located in the U.S.? If not, complete line 12.		X
12.	Is line 8 at least 6 times line 3?	X	

I hereby certify that the wording of this letter is identical to the wording specified in LAC 33:VII.727.A.2.i.iv.(e).

March 26, 2007

CHEVRON CORPORATION

By: ______________________

Stephen J. Crowe
Vice President and Chief Financial Officer

SOLID WASTE FACILITY
CORPORATE GUARANTEE
FOR CLOSURE

Guarantee made this 26th day of March, 2007 by CHEVRON CORPORATION, a business corporation organized under the laws of the State of Delaware, hereinafter referred to as guarantor, to the Louisiana Department of Environmental Quality, obligee, on behalf of our subsidiary CHEVRON U.S.A. INC. of 6001 Bollinger Canyon Road, San Ramon, California.

Recitals

1. The guarantor meets or exceeds the financial test criteria and agrees to comply with the reporting requirements for guarantors as specified in LAC 33:VII.727.A.2.i.ix.

2. CHEVRON U.S.A. INC. is the permit holder, hereinafter referred to as permit holder, for the following solid waste facilities covered by this guarantee:

Site ID No. GD-075-1511/ Permit # P-0112		
Chevron U.S.A. Inc.	Closure Cost	$2,461,193
Oak Point Plant	Post-Closure	0
Highway 23 – P.O. Box 70	(clean closure)	
Belle Chasse, LA 70039		

3. "Closure plans" as used below refers to the plans maintained as required by the Louisiana Administrative Code, Title 33, Part VII for the closure and post-closure care of the facilities identified in Paragraph 2 above.

4. For value received from permit holder, guarantor guarantees to the Louisiana Department of Environmental Quality that in the event that permit holder fails to perform closure and post-closure care of the above facilities in accordance with the closure plan and other permit requirements whenever required to do so, the guarantor shall do so or shall establish a trust fund as specified in LAC 33:VII.727.A.2.d. as applicable, in the name of permit holder in the amount of the current closure and/or post-closure estimates as specified in LAC 33:VII.727.A.2.

5. For value received from permit holder, guarantor guarantees to any and all third parties who have sustained or may sustain bodily injury or property damage caused by sudden and accidental occurrences arising from operations of the facilities covered by this guarantee that in the event that permit holder fails to satisfy a judgment or award based on a determination of liability for bodily injury or property damage to third parties caused by sudden and accidental occurrences arising from the operation of the above-named facilities, or fails to pay an amount agreed to in settlement of a claim arising from or alleged to arise from such injury or damage, the guarantor will satisfy such judgment(s), award(s), or settlement agreement(s) up to the coverage limits identified above.

6. The guarantor agrees that if, at the end of any fiscal year before termination of this guarantee, the guarantor fails to meet the financial test criteria, guarantor shall send within 90 days, by certified mail, notice to the administrative authority and to permit holder that he intends to provide alternative financial assurance as specified in LAC 33:VII.727.A.1 and/or LAC 33:VII.727.A.2, as applicable, the name of the permit holder, within 120 days after the end of such fiscal year, the guarantor shall establish such financial assurance unless permit holder has done so.

7. The guarantor agrees to notify the administrative authority, by certified mail, of a voluntary or involuntary proceeding under Title 11 (bankruptcy), U. S. Code, naming guarantor as debtor, within 10 days after commencement of the proceeding.

8. The guarantor agrees that within 30 days after being notified by the administrative authority of a determination that guarantor no longer meets the financial test criteria or that he is disallowed from continuing as a guarantor of liability coverage or closure and/or post-closure care, he shall establish alternate financial assurance as specified in LAC 33:VII.727.A.1 and/or LAC 33:VII.727.A.2 as applicable, in the name of permit holder, unless permit holder has done so.

9. The guarantor agrees to remain bound under this guarantee notwithstanding any or all of the following: amendment or modification of the closure and/or post-closure care; the extension or reduction of the time of performance of closure and/or postclosure; or any other modification or alteration of an obligation of the permit holder pursuant to the Louisiana Administrative Code, Title 33, Part VII.

10. The guarantor agrees to remain bound under this guarantee for so long as the permit holder must comply with the applicable financial assurance requirements of LAC 33:VII.727.A.1 and/or LAC 33:VII.727.A.2 for the above- listed facilities except that guarantor may cancel this guarantee by sending notice by certified mail, to the administrative authority and to the permit holder, such cancellation to become effective no earlier than 90 days after receipt of such notice by both the administrative authority and the permit holder, as evidenced by the return receipts.

11. The guarantor agrees that if the permit holder fails to provide alternate financial assurance as specified in LAC 33:VII.727.A.1 and/or LAC 33:VII.727.A.2, as applicable, and obtain written approval of such assurance from the administrative authority within 60 days after a notice of cancellation by the guarantor is received by administrative authority from guarantor, guarantor shall provide such alternate financial assurance in the name of the permit holder.

12. The guarantor expressly waives notice of acceptance of this guarantee by the administrative authority or by the permit holder. Guarantor expressly waives notice of amendments or modifications of the closure and/or post-closure plan and of amendments or modifications of the facility permit(s).

I hereby certify that the wording of this guarantee is identical to the wording specified in LAC 33:VII.727.A.2.i.ix(1), effective on the date first above written.

Effective date: March 26, 2007

CHEVRON CORPORATION

By ______________________
Stephen J. Crowe
Vice President and Chief Financial Officer

State of California) ss.
)
County of Contra Costa)
) ss.
City of San Ramon)

Subscribed and sworn to before me on this 26th day of March, 2007 by Stephen J. Crowe personally known to me or proved to me on the basis of satisfactory evidence to be the person who appeared before me.

NOTARY SEAL

NOTARY SIGNATURE

SCOTT BANKS
Commission # 1719486
Notary Public - California
Contra Costa County
MyComm. Expires Jan 22, 2011

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Three Embarcadero Center
San Francisco CA 94111-4004
Telephone (415) 498 5000
Facsimile (415) 498 7100

Report of Independent Accountants

To the Board of Directors of Chevron Corporation:

We have performed the procedures enumerated below, which were agreed to by the management of the Company, solely to assist you in respect to certain financial information included in the letter dated March 26, 2007 from the Vice President, Finance of the Company to the Louisiana Department of Environmental Quality (the "Letter"). The management of the Company is responsible for the financial information included in the Letter. This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. The sufficiency of these procedures is solely the responsibility of those parties specified in this report. Consequently, we make no representation regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

The procedures and the associated findings are as follows:

1. We recalculated all formulas included in the Letter to determine mathematical accuracy and found no differences.

2. a. We compared the Net Worth of the Company at December 31, 2006, as stated in the enclosed Schedule A, to amount set forth as *Total Stockholders' Equity* in the consolidated financial statements included in the Company's 2006 Annual Report on Form 10-K. We found no difference.

   b. We compared the Intangible Assets of the Company at December 31, 2006, as stated in the enclosed Schedule A, to a supporting schedule prepared by the Company from its accounting records. We also recalculated the mathematical accuracy of the supporting schedule. We found no exceptions as a result of the procedures.

   c. We compared the Tangible Net Worth of the Company, as stated in Schedule A, to the corresponding amount as stated in the Letter. We found no difference.

3. We compared the Total Assets in the U.S. of the Company at December 31, 2006, which amounted to $45,258,000,000, to the amount set forth as *Total Assets – United States* in Note 8 to the consolidated financial statements included in the Company's 2006 Annual Report on Form 10-K. We found no difference.

PRICEWATERHOUSECOOPERS

The Board of Directors of Chevron Corporation
Page 2

4. We recalculated the percentage of the Total Assets in the U.S., as stated in 3 above, of the amount set forth as *Total Assets* in the consolidated balance sheet included in the Company's 2006 Annual Report on Form 10-K and agreed that this percentage is less than 90%.

We were not engaged to and did not conduct an examination, the objective of which would be the expression of an opinion on the specified elements, accounts, or items referred to in 1 to 4 above. Accordingly, we do not express such an opinion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

This report is intended solely for the information and use of the Company and the Louisiana Department of Environmental Quality, and is not intended to be and should not be used by anyone other than these specified parties.

PricewaterhouseCoopers LLP

March 26, 2007

PRICEWATERHOUSECOOPERS

Schedule A

Tangible Net Worth of Chevron Corporation at December 31, 2006.

Net Worth	$ 68,934,691,000
Intangible Assets	(4,964,353,000)
Tangible Net Worth of Chevron Corporation	$ 63,970,338,000

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Enter # <GO> for historical ratings.

Related Functions   Company Tree Ratings   CREDIT PROFILE

Chevron Corp   Page 1/1

MOODY'S		FITCH	
1) Outlook	STABLE	12) Outlook	STABLE
2) Issuer Rating	Aa2	13) LT Issuer Default Rating	AA
3) Foreign Currency LT Debt	WR	14) Senior Unsecured Debt	AA
4) Local Currency LT Debt	WR	15) Short Term	F1+
5) Senior Unsecured Debt	WR	16) ST Issuer Default Rating	F1+
6) Short Term	P-1		
STANDARD & POOR'S		DBRS	
7) Outlook	STABLE	17) Outlook	STABLE
8) LT Foreign Issuer Credit	AA	18) Senior Unsecured Debt	AA
9) LT Local Issuer Credit	AA	DUFF & PHELPS	
10) ST Foreign Issuer Credit	A-1+	19) Senior Unsecured Debt	WR
11) ST Local Issuer Credit	A-1+		

Chevron

Lisa M. Lemanczyk
Senior Counsel

Law Department
Chevron U.S.A. Inc.
6001 Bollinger Canyon Road
San Ramon, CA 94583
Tel 925-842-5037
Fax 925-842-2011
LisaLemanczyk@chevron.com

November 15, 2006

Mr. Michael J. Rich
Deputy Attorney General
Delaware Department of Insurance
841 Silver Lake Blvd.
Dover, DE 19904

Dear Mr. Rich:

Chevron U.S.A. Inc. is renewing a Solid Waste Permit with the Louisiana Department of Environmental Quality. The renewal process requires Chevron U.S.A. Inc. to submit a corporate guarantee to ensure the performance of closure and postclosure environmental remediation pursuant to Title 33, Part VII, Chapter 7, Subchapter E, Section 27, (A)(1)(d)(iv)(b) of the Louisiana Administrative Code. This provision also requires a written statement from the attorney general(s) or insurance commissioner(s) of the state in which the guarantor is incorporated stating that a corporate guarantee is a legally valid and enforceable obligation in that state. Accordingly, we are requesting that your office provide us with this statement.

If you should have any questions or require additional information, please do not hesitate to contact me. Your assistance is greatly appreciated.

Sincerely,

Lisa M. Lemanczyk

Lisa M. Lemanczyk

cc: Mr. Troy Sampey

Chevron

Lisa M. Lemanczyk
Senior Counsel

Law Department
Chevron U.S.A. Inc.
6001 Bollinger Canyon Road
San Ramon, CA 94583
Tel 925-842-5037
Fax 925-842-2011
LisaLemanczyk@chevron.com

November 15, 2006

James J. Donelon
Commissioner
Louisiana Department of Insurance
1702 N. 3rd St.
Baton Rouge, LA 70802

Dear Commissioner Donelon:

Chevron U.S.A. Inc. is renewing a Solid Waste Permit with the Louisiana Department of Environmental Quality. The renewal process requires Chevron U.S.A. Inc. to submit a corporate guarantee to ensure the performance of closure and postclosure environmental remediation pursuant to Title 33, Part VII, Chapter 7, Subchapter E, Section 27, (A)(1)(d)(iv)(b) of the Louisiana Administrative Code. This provision also requires a written statement from the attorney general or insurance commissioner of the state of Louisiana stating that a corporate guarantee is a legally valid and enforceable obligation in that Louisiana. Accordingly, we are requesting that your office provide us with this statement.

If you should have any questions or require additional information, please do not hesitate to contact me. Your assistance is greatly appreciated.

Sincerely,

Lisa M. Lemanczyk

Lisa M. Lemanczyk

cc: Mr. Troy Sampey

Chevron

Lisa M. Lemanczyk
Senior Coursel

Law Department
Chevron U.S.A. Inc.
6001 Bollinger Canyon Road
San Ramon, CA 94583
Tel 925-842-5037
Fax 925-842-2011
LisaLemanczyk@chevron.com

November 15, 2006

Ms. Megan Terrell
Assistant Attorney General
Environmental Outreach
P.O. Box 94005
Baton Rouge, LA 70804

Dear Ms. Terrell:

Chevron U.S.A. Inc. is renewing a Solid Waste Permit with the Louisiana Department of Environmental Quality. The renewal process requires Chevron U.S.A. Inc. to submit a corporate guarantee to ensure the performance of closure and postclosure environmental remediation pursuant to Title 33, Part VII, Chapter 7, Subchapter E, Section 27, (A)(1)(d)(iv)(b) of the Louisiana Administrative Code. This provision also requires a written statement from the attorney general(s) or insurance commissioner(s) of the state of Louisiana stating that a corporate guarantee is a legally valid and enforceable obligation in that state. Accordingly, we are requesting that your office provide us with this statement.

If you should have any questions or require additional information, please do not hesitate to contact me. Your assistance is greatly appreciated.

Sincerely,

Lisa M. Lemanczyk

Lisa M. Lemanczyk

cc: Mr. Troy Sampey

Appendix Y

Correspondence

DEPARTMENT OF ENVIRONMENTAL QUALITY

KATHLEEN BABINEAUX BLANCO
GOVERNOR

JUN 2 1 2007

MIKE D. McDANIEL, Ph.D.
SECRETARY

CERTIFIED MAIL 7003 2260 0005 9323 3106
RETURN RECEIPT REQUESTED

Mr. M. H. Burnside
Chevron Oronite Company, LLC
P.O. Box 70
Belle Chase, LA 70037

RE: Request for Final Copies of Permit Renewal Application
Storm Water Oil/Water Separator Treatment System
Chevron Oronite Company, LLC
AI # 1708 / PER20050009 / GD-075-1511 / P-0112
Plaquemines Parish

Dear Mr. Burnside:

The Waste Permits Division has conducted a review of your permit renewal application for the referenced solid waste facility.

Please submit to the Division, six (6) bound copies of the complete permit application, and therein incorporating all previously accepted revisions in appropriate sections. Upon receipt of these copies, a final review will be conducted to ensure that the document is acceptable for public review. Your updated permit application shall be sent to this office within thirty (30) days of receipt of this letter. If upon this review, the document is determined to be technically complete, you will be notified of this decision and the public review period will be scheduled.

Please reference the Agency Interest Number AI#1708, Permit Activity Number PER20050009, and Permit Number P-0112 on all correspondence to this office pertaining to this permit renewal application. If you have any questions or comments concerning this matter, please contact Mr. Hoa Van Nguyen at 225-219-3047.

Sincerely,

Bijan Sharafkhani

Bijan Sharafkhani, P.E.
Administrator
Waste Permits Division

hvn

ENVIRONMENTAL **SERVICES**
: PO BOX 4313, BATON ROUGE, LA 70821-4313
P:225-219-3181 F:225-219-3309
WWW.DEQ.LOUISIANA.GOV

Chevron

Oronite

Mike Burnside
Americas Regional
Manager

Oak Point Plant
Chevron Oronite Co. LLC
P. O. Box 70
10285 Highway 23
Belle Chasse, LA 70037
Tel 504-391-6101
Fax 504-391-6356

April 24, 2007

Mr. Bijan Sharafkhani, Administrator
Waste Permits Division
Louisiana Department of Environmental Quality
P.O. Box 4313
Baton Rouge, Louisiana 70821-4313

Subject: **Solid Waste Permit Renewal**
Storm Water Treatment System
Response to 2nd Notice of Deficiency/Permit Renewal Application
AI No. 17080/PER 20050009/GD-075-1511/Permit No. P-0112-A-1
Chevron Oronite Company, LLC, Belle Chasse, Louisiana

Dear Mr. Sharafkhani:
The Louisiana Department of Environmental Quality-Waste Permits Division's 2nd Notice of Deficiency/Permit Renewal Application letter dated February 21, 2007, required responses to comments related to the permit renewal application for the Storm Water Oil/Water Separator Treatment System. With this letter, Chevron Oronite Company, LLC (Chevron), provides responses to each comment. Chevron's response to each comment is listed in boldface type below the comment.

NOD Comments and Responses

General Please be advised that subchapters §709 and §713 from the first submittal of the permit application should be retained. They are not included in the list to be removed. So, table of contents should have §709, §713, and §727 under Chapter 7; and all sections and responses to §709 and §713 inserted in responses to §521 should be removed and relocated to appropriate subchapter in chapter 7.

Please use appropriate tabs to separate all chapters (519, 520, 521, 523, 709, 713, and 727), all appendices, exhibits, tables, references, etc. (See LAC 33:VII.513.B.2.a.).

Comment noted. Subchapters §709 and §713 will be retained and the responses provided to these subchapters will be removed from the responses to §521. A copy of the revised Chapter 5 and Chapter 7 is included in Attachment A.

Appropriate tabs will be used to separate all chapters, appendices, exhibits, tables, and references in the final permit document.

519.Q. Re-submit the proof of publication from The Advocate. The proof provided in Appendix B of the NOD response is incorrect.

Attachment B contains a copy of the proof of publication from The Advocate.

519. The incomplete Part I in Attachment A should be replaced by the signed Part I in Attachment C.

Comment noted. The signed Part I will be included in the final permit application.

521.A.1.e. Update the responses to 521.A.1.e.i, ii, and iii to address:

- The new correspondence from LDWF dated Feb 1, 2006 and
- The new correspondence from USACE dated May 24, 2006.

The response to 521.A.1.e.i has been revised to address the new correspondence from LDWF and the USACE. Specifically, Table 2 has been updated as follows:

Table 2 - List of Environmental Resources Within 1,000 Feet of the Storm Water Treatment System

Historic Sites	None
Recreational Areas	Chevron Park
Archaeological Sites	None
Designated Wildlife Management Areas	None
Swamps, Marshes and Wetlands	Jurisdictional Wetlands, Coastal Management Zone
Endangered Species and Other Critical Habitats	pallid sturgeon (Scaphirhychus albus)
Wild and Scenic Rivers and Other Sensitive Ecological Areas	None

The 521.A.1.e.ii language has been revised to the following:

Appendix D contains a copy of the State Historic Preservation Office (SHPO), Louisiana Department of Culture, Recreation & Tourism, Office of Cultural Development letter dated February 3, 2006, stating that no archaeological sites or historical structures exist within 1,000 feet of the Storm Water Treatment System. The only recreational area nearby is Chevron Park, a recreation area owned by Chevron for use by employees and their families. Figure 5 identifies the location of the park, which is situated within the boundaries of the plant.
Appendix E contains a copy of the Louisiana Department of Wildlife and Fisheries (LDWF) letter dated February 1, 2006, which identifies the pallid sturgeon (Scaphirhycus albus) as an endangered species. The pallid sturgeon has

been identified in the Mississippi River. The Mississippi River is greater than 1,000 feet from the Storm Water Treatment System area. Additionally, LDWF requests that steps be taken to avoid the degradation of water quality in the Mississippi River. Because effluent from the Chevron facility is managed under LDEQ water discharge permits, no degradation of Mississippi River water quality is anticipated and no actions are required to address the LDWF comment. LDWF has identified that no wildlife management areas are in the immediate vicinity and they are not aware of any nearby designated sensitive ecological areas.

Appendix F contains a copy of the U.S. Department of the Army, New Orleans District, Corps of Engineers letter dated May 24, 2006, which identified jurisdictional wetlands under Section 404 of the Clean Water Act within 1,000 feet of the Storm Water Treatment System. No permit is necessary for the existing facility. Any expansion of the Storm Water Treatment System or Interconnecting Ditches that would impact the jurisdictional wetlands may require a permit from the USACE.

The 521.A.1.e.iii language has been revised to the following:

Chevron Park is located within the boundaries of the Oak Point Plant. There is a perimeter fence around the park to prevent people from entering the plant or the landfill areas. The park is protected from runoff from the plant and the landfills by the railway tracks to the west, a ditch to the south, a ditch to the north, and a levee to the east.

The LDWF letter stated that steps should be taken to avoid the degradation of water quality in the Mississippi River. Chevron's Oak Point Plant closely monitors all discharges to the Mississippi River to ensure that all discharges are within the limits of the LPDES Permit; therefore, no additional action is required. The jurisdictional wetland identified by the U.S. Department of the Army, New Orleans District, Corps of Engineers is within 1,000 feet of the Storm Water Treatment System. Because the unit is not on jurisdictional wetlands and the unit received waste prior to October 9, 2003, no action is required. Any expansion of the Storm Water Treatment System or Interconnecting Ditches that would impact the jurisdictional wetlands may require a permit from the USACE.

521.F.1. Provide the certification to meet the standard of 713.B.1.

The certification of this permit application by the preparers of the permit is provided in Attachment C and will be incorporated in Appendix P of the revised permit.

521.G.1.a. Address the reports requirements to meet LAC 33:VII.713.C.1.a.

The response to LAC 33.VII.713.C.1.a states:

Chevron will submit an annual report to LDEQ indicating the estimated remaining permitted capacity at the facility as of the end of the reporting period (expressed in wet-weight tons) for the period of July 1 through June 30 of a given year. All calculations used to determine the amounts of solid waste received for disposal and to determine remaining capacity during the annual reporting period

will be submitted to LDEQ. Chevron will submit the annual report no later than August 1 of a given year. The seven-digit industrial waste number assigned by LDEQ will be used in the annual report. Reporting requirements will terminate upon closure of the facility.

521.L.3. Please be advised that there are only three subsections under 521.L.3. They are 521.L.3.a, b, and c. There is no subsection 521.L.3.d.

Comment noted. Section 521.L.3.d has been deleted.

521.L.4. It is noted that 521.L.4 is labeled incorrectly as 521.L.3.d.

Comment noted.

Geological Comments

521.F.5.c. The response to this NOD is acceptable, if the response is reflected in the revised Groundwater Sampling and Analysis Plan, which was not provided for review. Be advised that the Groundwater Sampling and Analysis Plan may require further revision after contaminant characterization analyses for AOC 1 and AOC 2 are completed.

Comment noted.

Additional Information

Chevron has provided a copy of the Irrevocable Letter of Credit (Attachment D) which will be used as the mechanism to satisfy Section 727.A.1 (Current Operations). The Standby Trust Fund information will be included in Appendix X of the final permit submittal. The Financial Test/Corporate Guarantee will be used to satisfy Section 727.A.2 (Closure/Post-Closure) will also be provided in Appendix X of the final permit submittal.

Sincerely,

M. H. Burnside

Attachment A	Revised Chapter 5 and Chapter 7
Attachment B	Proof of Public Notice
Attachment C	Certification Statement
Attachment D	Letter of Credit